December 20, 2019

Arizona Corporation Commission
1200 W. Washington Street
Phoenix, AZ 85007

Stakeholder Comments in Response to Chairman Burns' October 15 Letter on IRP Process in Docket No. RU-00000A-18-0284

Dear Chairman Burns and Commissioners:

I. Chairman Burns' Proposal Significantly Improves Arizona's IRP Rules.

The Joint Stakeholders appreciate Chairman Burns' emphasis on facilitating stakeholder engagement throughout the Integrated Resource Plan (IRP) process and his proposal to require all-source "request for proposals" (RFP) before a utility selects resources for its final IRP. Both components are essential to a well-informed and effective IRP process.

Chairman Burns' outline provides a solid foundation from which to build a comprehensive IRP Rule. Chairman Burns correctly identifies the importance of developing the load forecast, which may be the most critical element of developing an IRP. However, there are other vital assumptions that require Commissioner and stakeholder input at the outset; these assumptions are necessary to evaluate the resources contemplated in an RFP reasonably. For example, additional assumptions include the projected price of natural gas and other fuels, the capacity credit that variable renewable resources receive, and the cost to comply with future regulations, to name a few. In addition to these, we recommend building on the stakeholder engagement and all-source RFP (or RFI) provisions within the Chairman's proposal. Critical elements of the Joint Stakeholder Proposal, submitted on July 30, 2019, can further improve the IRP process, increasing transparency and the robust evaluation of future utility investments.

This letter provides our recommendations to enhance and expand upon the proposal, including ways to incorporate other aspects of the Joint Stakeholder Proposal within a revised IRP Rule.

We understand any revision of the IRP rules will be an iterative process, and we look forward to working with Chairman Burns, the Commission, and Staff to create a revised draft IRP Rule. We are happy to answer questions or provide further information, as needed.

II. Recommendations to Build Upon Chairman Burns' Proposal for Stakeholder Engagement in the IRP and the All-Source RFP

a. The IRP Rule should require stakeholder input at the outset, including mandatory open input into the utility's assumptions for the load forecast.

The early and regular engagement of regulators and stakeholders in a pre-filing process is critical to form a consensus plan and to protect the public interest. At the close of the IRP process, the utility must have a plan from which to make productive decisions. Rather than litigating an exclusively utility-driven plan after its submission—a process that may not result in a satisfactory outcome to any party—the IRP should solicit and reflect input during its formation in a pre-filing stakeholder process at the time when the utility is selecting and modeling various portfolios. We also recommend stakeholders have an opportunity to provide input on modeling assumptions and have access to the modeling platforms. This recommendation requires regular opportunities for stakeholders to engage meaningfully, early, and often.

Chairman Burns proposes stakeholder opportunities through (1) informal meetings while the load forecast is being developed, as well as workshops and open meetings after it is presented; (2) a stakeholder objection option after the all-source RFP is finalized; and (3) workshops after the utility selects resources based on the all-source RFP. In Section R14-2-706(I)(4)(a) of the Joint Stakeholders' Proposal, we recommended at least four stakeholder meetings for the following purposes:

> (1) At the beginning, to collaborate on the planning approach, priorities, and evaluation criteria;
> (2) Prior to extensive analysis, to discuss model input assumptions and analysis structure;
> (3) Post-analysis, to discuss the results and draw conclusions about the import of those results; and
> (4) After a final draft IRP has been developed, to present findings and the resulting actions before it is filed with the Commission.[1]

[1] For example, in Indiana, the de facto IRP Rule requires a minimum of two meetings with stakeholders—one introductory meeting and one regarding the utility's preferred resource portfolio—and allows for additional meetings depending on level of interest. 170 Ind. Admin. Code 4-7-2.1(e)(1)-(2) (proposed Oct. 4, 2012) (Attached as Exhibit 1).

Chairman Burns' proposal provides for full stakeholder engagement at two points: the load forecast and the utility's resource selection. Although these opportunities would facilitate some stakeholder engagement, the entire process of modeling and selecting a range of portfolios for the draft IPR should also be open to stakeholders. We recommend incorporating additional opportunities in order to make the process more robust.

Specifically, we recommend expanding opportunities to include more formal input before the load forecast is developed to enable input into the assumptions. Chairman Burns' proposal includes an informal process with meetings for input into the load forecast, but access to that informal process would be in the hands of the utility. Therefore, we recommend the Commission establish a standard pre-filing, informal workshop process. We recognize that such participation may require stakeholders to take steps to protect the utility's confidential information. But the Commission should exert reasonable oversight regarding potentially oppressive "non-disclosure agreements," as we recommend in section III.g below.

In addition, we recommend expanding the objection process Chairman Burns proposed for the all-source RFP. Although Chairman Burns' proposal provides the Commission an option to consider stakeholder objections, it would only allow feedback after the utility has finalized the RFP and does not guarantee that stakeholders can participate. We therefore recommend the process incorporate stakeholder feedback up front—so that stakeholder recommendations can be incorporated *before* the RFP is finalized—and include an opportunity to comment on the utility's narrative on the particular energy shortfall it needs to fill. We recommend similar pre-filing opportunities for stakeholder input before the utility proposes its resource selection decision to the Commission.

b. <u>The Joint Stakeholders support the implementation of an all-source "request for information," which should identify independent needs where possible and should facilitate stakeholder input.</u>

The Stakeholders support Chairman Burns' proposal to incorporate an all-source RFP to inform the resource selection component of the IRP. In particular, we appreciate that Chairman Burns has recommended requiring a technology-, location-, and size-neutral RFP that, in addition to supply-side resources, would include customer-owned resources such as demand-side management, energy efficiency, and customer-owned rooftop solar. We support this general approach for two primary reasons.

First, it is essential to base resource decisions on accurate and up-to-date information about resource costs. Market conditions can change rapidly and may shift the outcomes of even a robust plan. As such, the IRP Rule should require utilities to do market tests before—or while—constructing their IRPs to look at the actual costs of energy options. One option is to issue a broad RFP, as Chairman Burns proposed, for capacity and energy to inform pricing and key characteristics of resources (particularly wind, solar, storage, solar plus storage, demand-side management, and energy efficiency) to be evaluated in the IRP.

Second, as Chairman Burns acknowledged, it is important that the RFP not dictate specific resource technology, size, or location. Rather, the RFP should be highly specific about each identified supply-side need so that a wide range of market participants can reasonably assess their ability to meet the criteria: i.e., 250 MW of capacity available during winter-season, peak hours from 5-9pm, or 120 MW of fast-ramp (up, or up and down) available from 4-6pm during summer hours. An RFP that is too prescriptive risks closing the door to lower-cost or lower-risk alternatives that might bring other benefits to the system. For example, Indiana recently rejected an "unduly restrictive" RFP because its narrow "focus on a large baseload dispatchable resource limited the options [the utility] evaluated to those larger than 600 MW" and the utility therefore "foreclosed consideration of combinations of smaller resources that might have offered greater resource diversity, flexibility and cost efficiencies than reliance on the acquisition of a single large natural-gas facility."[2] As the Indiana Commission explained, "expansion of the RFP to consider a broader spectrum of resource options would have . . . gone a long way to improve the metrics to limit risks from exposure to changes in market conditions and technologies."[3] As such, and as proposed by Chairman Burns, the RFP should consider demand-side resources, including demand-side management and energy efficiency, on equal footing as supply-side resources and must not be limited to "dispatchable" resources.

Although we support Chairman Burns' general approach, we recommend two changes. First, the process should be reframed as a "request for information" (RFI) to acknowledge that the bids will be used to inform the planning process but will not lock in specific projects.[4] Rather, the resulting bids will form a cohort of known new resource options with appropriate pricing and availability that will inform the IRP's anticipated resource selection. When it comes time for the utility to acquire generation to meet IRP-identified needs, however, the utility should select specific projects based on an all-source RFP. This two-step process will ensure the least-cost and least-risk resource is used to satisfy each need, as it arises.

Second, the RFI included in the IRP process should split apart mandated operational requirements where possible, such that bidders may propose technologies that address independent requirements without having to meet all types of need. This approach will enhance

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[2] Order of the Comm'n, No. 45052 at 21, (Ind. Util. Regulatory Comm'n, Apr. 24, 2019), *available at* https://www.in.gov/iurc/files/45052_ord_20190424102046480.pdf.
[3] *Id.*
[4] Joint Stakeholder Proposal R14-2-707(A)(2) (requiring resource options to be informed by an all-source "request for information"); R14-2-702(5) (defining all-source RFI). Note that the requirement for an all-source RFI should also be added under the New Source Options in R14-2-706(E) but was omitted in the Joint Stakeholder Proposal due to an oversight.

the flexibility and variability of resources that may be combined into a least-cost portfolio that satisfies all identified needs.

III. Additional Measures that Will Enhance Chairman Burns' Proposal

As noted, the Joint Stakeholders support Chairman Burns' proposal for a revised IRP Rule, but there are opportunities to expand the proposal and include additional issues his proposal does not address. We, therefore, include a number of recommendations to expand upon the proposal. Potential language for implementing the following recommendations is included within the Joint Stakeholder Proposal, submitted on July 30, 2019.

a. The IRP Rule should require the evaluation of existing resources and any identified resource shortfalls.

To ensure that Arizona customers are benefiting from the most cost-effective energy resources available, the utility's resource selection—and the all-source RFI—should be based on the results of a comprehensive resource needs assessment that combines the load forecast with an evaluation of existing resources.[5] The resulting comprehensive resource needs assessment will identify the timing, scope, and circumstances of potential future utility shortfalls relative to customer demand, which should shape the all-source RFI and ultimate resource selection.

As part of this analysis, utilities should be required to conduct economic shut-down analyses for current supply resources, including an evaluation of those resources' ongoing capital and production costs as compared to alternative demand-side, market, or supply-side resources.[6] In the past, utility resource planning largely consisted of responding to growing electricity demand by building the most cost-effective new resources available. However, in recent years, stagnant electricity demand has limited the degree of load-driven need for new resources. At the same time, rapidly falling costs for renewable energy resources and energy storage, recent environmental regulations, and low gas prices have put increasing economic pressure on existing generation resources.[7] Given these factors, it is no longer safe to assume that all existing generation resources comprise a least-cost, least-risk resource plan. Instead, an IRP should include an assessment of the economics of continuing to operate existing units compared to retiring them in the near term.[8]

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[5] *See* Joint Stakeholder Proposal R14-2-706(C)-(D).

[6] *See* Ex. 1, 170 Ind. Admin. Code 4-7-6(a)(2).

[7] U.S. Energy Information Administration. December 28, 2018. Today in energy: U.S. coal consumption in 2018 expected to be the lowest in 39 years. *Available at* https://www.eia.gov/todayinenergy/detail.php?id=37817.

[8] In Puerto Rico's IRP Rule, for instance, the utility is required to "[r]ecognize all utility-borne costs, as well as avoided costs, associated with the retirement or modification of existing resources" as part of its resource plan development analysis. P.R. Regs. CEEPR REG. 9021 § 2.03(H)(2)(a)(i)(D) (Attached as Exhibit 2). Using the load forecast and this existing resources evaluation, the utility should then conduct a resource needs assessment that "identif[ies] current and/or future expected capacity and/or energy requirements resulting from the expected or

As with the other components of the IRP process, it is essential that stakeholders have substantive opportunities to engage on the substance of the utility's resource shortfall analysis, including providing input on the existing resources evaluation.

b. <u>Following the all-source RFI, the IRP Rule should require the utility to develop a comprehensive resource plan with portfolio options.</u>

Based on the need assessment and results of the all-source RFI, the utility should be required to develop a selection of optimized alternative resource plans using various assumptions, forecasts, and resource portfolios.[9] Each alternative should satisfy the utility's need forecast through a balanced integration of both supply- and demand-side resources. The utility may then select a preferred plan from among these alternatives. This way, if the Commission disagrees with the preferred alternative selected by the utility, the Commission, Staff, and stakeholders will have the building blocks to consider other portfolio alternatives. As we recommend throughout, the Commission should ensure stakeholders have substantive opportunities to engage on the selection of resources and development of portfolio alternatives.

In addition, the Commission should continue to incorporate and to expand a holistic approach to the least-cost analysis in which Arizona utilities must consider relevant externalities.[10] Arkansas' IRP rule, for example, provides that "[c]ost effective resources that do not meet minimum criteria such as risk or environmental or other governmental rules or policy should be eliminated from further consideration."[11] Relevant costs that the Commission should evaluate include, but are not limited to:[12] public health and environmental impacts, including air pollution and water use; resiliency in the face of severe weather events; the cost of carbon emissions; relevant regulations from agencies outside the ACC; just transition impacts; and other socioeconomic effects[13] of an IRP.

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contractual retirement of, or cessation of services from, existing supply and demand-side resources when compared against forecast load conditions." *Id.*

[9] *See* Joint Stakeholder Proposal R14-2-706(G).

[10] *See, e.g.* Ariz. Admin. Code § R14-2-703(D)(16). *See also* Minn. R. 7843.0100(10); 0500(3)(C)-(E) (Attached as Exhibit 3); *In re* Public Utility Commission of Oregon, 255 P.U.R.4th 367, App. A, Guideline 4(e), (Jan. 8, 2007), *corrected by In re* Public Utility Commission of Oregon, 2007 WL 534555 (Feb. 9, 2007) (hereinafter "Or. IRP") (Attached as Exhibit 4).

[11] Ark. Admin. Code 126.03.22-4(4.3) (Attached as Exhibit 5).

[12] *See* Colo. Code Regs. § 723-3:3604(l) (Attached as Exhibit 6); Ariz. Admin. Code § R14-2-703(B)(1)(p), (D), (F)(3)(4), (I),704(B)(7); Ex. 2, P.R. Regs. CEEPR REG. 9021 §§ 2.03(C), (F)(1)(b)(vii); 3.01(B); Ex. 4, Or. IRP at Guideline 8; Ex. 5, Ark. Admin. Code 126.03.22-4(4.1); Commission Order Attachment, Puget Sound Energy's 2017 IRP 11-13, Docket Nos. UE-160918, UG-160919 (Wa. Utilities & Transp. Comm., May 7, 2018) (Attached as Exhibit 7).

[13] Minnesota defines "socioeconomic effects" as "changes in the social and economic environments, including, for example, job creation, effects on local economies, geographical concentration of persons and structures, concentration of investment capital, and the ability of low-income and rental households to receive conservation services." Ex. 3. Minn. R. 7843.0100(10).

When evaluating this broad range of externalities, it is critical that all IRP criteria, and especially any socio-economic and public health effects, be treated in a balanced manner. For example, if a utility is considering lost jobs from retiring an existing plant, it should also consider job increases from building a replacement plant or constructing other resources.

c. The IRP Rule should clarify the process for Commission review, including the consequences if the Commission rejects an IRP.

We recommend the Commission consider ways to clarify its IRP review process so utilities, stakeholders, and Staff are all on the same page about the approach. Section R14-2-707 of the Joint Stakeholder Proposal includes recommendations on how to define the Commission review process. Most importantly, the IRP Rule should clearly define the consequences if the Commission does not acknowledge an IRP.

For example, the Commission voted to not acknowledge the 2015-2016 resource plans submitted by APS, TEP, and UNS Electric, Inc. because, according to Commissioner Burns, it was time to send the utilities "a strong message" that the Commission would no longer tolerate resource plans that put ratepayers at risk by justifying resource decisions based on unrealistic projections of load growth.[14] Before moving ahead, Arizona needed a different way of planning that facilitated the development of a more diverse array of energy resources.[15]

Rather than follow the Commission's direction, however, TEP has continued to dive headlong into major new acquisitions of excess gas generation, including by constructing a combined 182 MW of new capacity in the form of ten reciprocating internal combustion engine (RICE) units and by entering into a power purchase agreement for and exercising its option to purchase 550 MW at Gila River Unit 2. In 2018, to ensure that the utilities would not lock in Arizona to an unsustainable energy future while the utilities improved their resource planning and the Commission revised its Energy Rules, the Commission temporarily prohibited—initially from March 29, 2018 to January 1, 2019[16] which was subsequently extended until August 1, 2019[17]—the procurement of gas generation of 150 megawatts (MW) or more, absent Commission approval. Yet the utilities continue to advocate for and rely heavily on gas infrastructure in their recently filed 2019-2020 preliminary IRPs.[18]

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[14] March 13, 2018 Open Meeting at 4:44–4:45 (Comm'r Burns) ("The consequence of not acknowledging the plan would [be to] send a strong message to the utilities to be more accurate in their load forecasting and give us a better plan.").

[15] *Id.* at 4:30–4:32 (Comm'r Burns); *id.* at 4:46–4:37 (Comm'r Tobin).

[16] IRP and Gas Moratorium Order at 51–52.

[17] Arizona Corp. Comm'n Decision No. 77086 at 2–3, Dkt. No. E-00000V-15-0094, Feb. 20, 2019.

[18] E.g., Ariz. Pub. Serv. Co, 2019 Preliminary Integrated Resource Plan at 10, 20, Dkt. No. E-00000V-19-0034 (Aug. 1, 2019) (explaining that "gas serves [as] an essential 'safety net' and bridge fuel" and that "gas resources are essential to providing reliable service under any future scenario"); Tucson Elec. Pwr., 2019 Preliminary Integrated Resource Plan at 17, No. E-00000V-19-0034 (July 1, 2019) ("TEP continues to evaluate and support the development of large scale, underground natural gas storage in Arizona.").

As the ongoing tension between Commission direction and utility action demonstrates, it is critical that the Commission's IRP Rule include clear accountability measures. In order to ensure the IRP process has meaning and is effective, the utility must be held accountable if the Commission does not acknowledge an IRP or specific action item. The IRP Rules should thus directly address rejection as a potential outcome. Although there are numerous options for accountability, we recommend that the IRP Rule include at least the following.

1. Authority to select alternative portfolio

The Commission should retain the authority to select an alternative resource portfolio if it disagrees with the utility's preferred portfolio. Under an IRP Rule that requires the utility to develop of a range of portfolio alternatives, as we recommend in section III.b,[19] the Commission would have the ability to choose an alternate portfolio, which would provide two primary benefits. First, the process would be more efficient because the Commission would have the ability to guide the utility's resource direction while simultaneously disagreeing with the utility's preference. Doing so would avoid the time and resources needed for additional analysis by the utility, input from stakeholders, and review by the Commission. Second, a utility could not simply avoid Commission review by failing to obtain an acknowledged IRP.

2. Rejection as a factor in subsequent rate cases

The Commission's decision regarding an IRP should be a factor in a subsequent rate case. Although decisions about allowing a utility to recover from customers the costs associated with new resources may only be made in a rate case proceeding, the Commission's acknowledgment or rejection of an IRP—or of an individual action item—is relevant to subsequent examination of whether a utility's resource investment is prudent and should be recovered from ratepayers. The utility will continue to carry the burden of demonstrating that it is entitled to recover its costs through customer rates, and a utility's decision to plow forward with acquiring resources contained within a rejected IRP should weigh strongly against a finding of prudency.

3. Clear standards for next steps following a decision to not acknowledge an IRP

The IRP Rule should establish clear requirements that a utility must complete following the rejection of an IRP. If the Commission decides not to accept any of the alternative portfolios developed by the utility, the IRP Rule should establish clear deadlines for the utility to provide additional analyses, stakeholders to participate in the revised IRP process, and Staff to complete its review of a revised proposal. Such requirements could represent a default scenario, which the Commission could modify in its order rejecting an IRP.

[19] *See* Joint Stakeholder Proposed Rules R14-2-706(G).

d. The IRP Rule should provide for a process to review and acknowledge IRP amendments between normally-scheduled IRPs.

To allow flexibility, section R14-2-2707(H) of the current IRP rules allows the utility to file an IRP amendment or update to an IRP if circumstances change between their 3-year IRP filings. However, the rules do not specify the subsequent process for review and approval of a modification. The Commission should take this opportunity to codify an amendment review process.

We recommend that the IRP Rule include a mechanism for the Commission's acknowledgement or denial of a proposed amendment that mirrors the review of a standard three-year IRP, including allowing opportunities for stakeholder input. Under the Joint Stakeholder proposal, a utility must request amendment for any "material change."[20] The Commission should also retain the right to require a utility to file for an amendment, where appropriate.

e. The IRP Rule should ensure utilities include just transition planning.

The IRP process is also an important opportunity for utilities to act on their responsibilities to assist the Navajo Nation, the Hopi Tribe, and other communities where coal generation is retired in their transition to a post-coal economy. This is particularly pressing, in light of the closure of the Navajo Generating Station (NGS) and the Kayenta coal mine that supplies it, and the upcoming closure of several other coal units. In Docket Nos. E-01345A-16-0036 and E-01345A-16-0123, Commission Staff supported the concept, presented in testimony by Navajo community organizations, that APS prepare a transition plan, "including a fund of several million dollars to assist the Navajo communities in transitioning to a future that is not heavily dependent upon coal."[21] Moreover, the administrative law judge in the proceedings ordered that given the impending closure of closure of NGS and San Juan Generating Station in northwestern New Mexico, "it is reasonable to require APS to begin establishing a transition plan for Four Corners and the impacted communities."[22] Towards that end, APS should be preparing a just transition plan as part of its anticipated 2019 rate case filing.

Clean energy development in communities where coal plants close will be a crucial part of just and equitable transition for the affected communities. And resource planning should consider and facilitate construction of clean energy projects within the spirit of that just transition.

[20] We recommend this provision should include "any new procurement effort or addition, retirement or modification of generation plant having a nameplate capacity of 50 megawatts or greater; the addition of pollution control equipment; the unanticipated termination of a Power Purchase Agreement; or other event, such as a major forest fire, as set forth by the Commission." Joint Stakeholder Proposal R14-2-702(34).

[21] Ariz. Corp. Comm'n, Recommended Opinion & Order from the Hearing Division at 17: 5-16, Dkt. Nos. E-01345A-16-0036 and E-01345A-16-0123 (Nov. 27, 2018), *available at* https://docket.images.azcc.gov/0000193887.pdf.

[22] Joint Stakeholder Proposal R14-2-708.

Therefore, we recommend the IRP Rule require utilities to consider and plan for a just transition throughout resource planning.

f. <u>The IRP Rule should include additional provisions to ensure transparency and access for stakeholders, including access to modeling software, assumptions, and work papers.</u>

The stakeholder engagement process should allow stakeholders to tangibly affect the outcome of a utility's IRP.[23] But in order to effectively engage in the process, stakeholders must have access to the pertinent data, including modeling inputs and assumptions, and stakeholder workshops. The Joint Stakeholder Proposal includes numerous provisions (e.g., R14-2-705(C), R14-2-706(F), (G)(2), (H), (I)(4)) intended to address this issue.

Our recommendations include making the data and software the utility relies upon as easily accessible as possible. For example, meetings should include access to the appropriate utility personnel and experts to answer questions. And the IRP Rules should require a utility to fully document, explain, and justify all of its assumptions, modeling, and analysis, as well as to provide all sources relied upon in its analysis within the IRP.[24]

In addition, utilities should be required to provide a license of the model(s) they use to Staff and intervenors, and to provide inputs and outputs and/or saved run files from the models. Some models have exorbitant, inflexible licensing fees that are only affordable for those utilities that are perpetually running and updating the same model for several different purposes. Others have pricing options that are more tailored toward intervenors, such as project-based or time-restricted licensing options that make it more feasible for entities other than the filing utility to look "under the hood" of the model.

The Commission could address this cost barrier by either requiring the utility to subsidize intervenor model access or requiring that utilities conduct reasonable model runs requested by intervenors. For example, in a recent pre-approval proceeding in Michigan, DTE Electric Company was required to provide intervenors access to the Strategist and PROMOD software it used to justify its proposed resource plan.[25] In Utah, Rocky Mountain Power has been required to provide web-based access to its production cost model as well as training in its use since 2005.[26] Meanwhile, the Washington Utilities and Transportation Commission generally requires that utilities using proprietary models ensure that intervenors are given the opportunity to request

[23] *See, e.g.,* Ex. 1, 170 Ind. Admin. Code 4-7-2.1(e)(4) (proposed Oct. 4, 2012).
[24] *See* Ex. 6, Colo. Code Regs. §§ 723-3:3604, 3606(e); Ariz. Admin. Code § R14-2-703(C)(3); Ex. 2, P.R. Regs. CEEPR REG. 9021 §§ 2.02(E), 2.03(C)(1)(d), (G)(1), (H)(1), 3.06; Ex. 3, Minn. R. 7843.0400(3)(A)-(D).
[25] Michigan Public Service Commission Docket No. U-18419, Ruling Granting Joint Motion to Compel Discovery at 21 (October 10, 2017).
[26] Report and Order of the Utah Public Service Commission in Docket No. 03-035-14 at 35 (Oct. 31, 2005).

alternative model runs.[27]

To complement stakeholder access to the modeling software itself, the Commission should require a utility's IRP modeling to:

> (1) be as transparent as possible and avoid legal or technical barriers to providing the inputs and outputs of a modeling exercise in legible, computer-readable format to interested parties;
> (2) use capacity expansion capabilities to develop least-cost portfolios;
> (3) include use of models with the ability to model at the hourly and sub-hourly level; and,
> (4) have the capability to reasonably represent emerging technologies such as battery storage and renewables.[28]

g. <u>The Commission should establish clear rules for when and how the Commission will resolve disputes about unreasonable non-disclosure agreements that effectively prohibit stakeholder engagement.</u>

To ensure that stakeholders and Staff have access to all of the pertinent data, the IRP Rule should recognize that, as a regulated entity, a utility may only withhold information from reporting with Commission approval. The Joint Stakeholders recognize that "confidential business information" relevant to the development of an IRP needs to be protected. Therefore, we are willing to accept reasonable non-disclosure agreements that are designed primarily to ensure that the parties may view, but not disclose publicly, such information. These agreements can provide assurance to the utility interested stakeholders will take steps to protect the utility's interest in confidentiality.

However, the agreements must effectively balance the utility's interest in limiting access to confidential business information with the public's right to access information and the Commission's interest in engaging stakeholders in the IRP process. Especially heavy-handed, vague, or otherwise one-sided agreements can expose stakeholders to extreme financial liability or other sanctions for breach, which may ultimately suppress stakeholder engagement. As a result, utilities may attempt to use aggressive agreements to prevent stakeholders from effectively participating in the IRP process. Such an outcome would impede the Commission's interest in broad input from a variety of stakeholders. Because the reasonableness of these agreements is typically context-specific, it may be difficult to establish bright-line rules on what is appropriate.

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[27] *See, e.g.*, Washington Utilities and Transportation Commission Dockets UE-151069 and 161024, Report and Policy Statement on Treatment of Energy Storage Technologies in Integrated Resource Planning and Resource Acquisition at 12 October 11, 2017.

[28] For example, Puerto Rico requires utilities to use a capacity expansion model and demonstrate that it had the capability to accomplish basic needs. Ex. 2, P.R. Regs. CEEPR REG. 9021 § 2.03(H)(2)(a)(i)-(iii).

The Joint Stakeholders therefore recommend that the Commission establish, in the IRP Rule, a process for parties to seek review of non-disclosure agreements involving unreasonable financial exposure or other risks, which may prevent participation in IRP proceedings.[29] Similarly, the IRP Rule should provide stakeholders a reasonable opportunity to challenge designations of information as confidential.[30]

h. The IRP Rule should include a statement of purpose.

The purpose of an IRP is to ensure that a utility creates a long-term resource plan that seeks a least-cost and least-risk solution for the utility's customers, to ensure that the near-term actions of the utility align with its long-term plans, and to engage regulators and the public in planning. A statement of purpose encourages utilities to consider the objectives of an IRP throughout the pre-submission process, and provides the Commission with a benchmark by which to evaluate the completeness and quality of a submitted IRP. The clear statements of purpose in Puerto Rico's and Oregon's IRP Rules, for example, embody this principle by emphasizing that utilities should focus their planning at all times on the best interest of the public.[31] Section R14-2-701 of the Joint Stakeholder Proposal includes our recommendation for a potential statement of purpose in Arizona.

i. The IRP Rule should include a five-year action plan that is technology-neutral.

In Section R14-2-706(J) of the July 30 proposal, the Joint Stakeholders recommend that the action plan be extended to cover a five-year period and be technology-neutral.[32] An expansion to a five-year action plan would benefit the Commission, utilities, and stakeholders by ensuring continuity of planning between IRP periods. Requiring IRPs every three years with simultaneous five-year action plans necessitates planning beyond the life of IRP development cycle, as illustrated in Table 1. The light orange represents the IRP development period (which usually takes 6-12 months, including stakeholders), followed by the release of the IRP (dark orange). The action plan (in blue) covers the period immediately following the IRP and is subject to Commission review. A five-year action plan *overlaps* the next IRP so that the utility is held accountable to its plans beyond just the next year alone. The latter years of a five-year action plan would, of course, be subject to change in a subsequent IRP process as new information comes to light. This type of overlap is not uncommon in other states' IRP

[29] The current IRP rule allows the utility to submit a request to Staff to protect confidential business information from disclosure through the standard data reporting requirements. *See* section R14-2-2703(L). However, the rule does not provide a mechanism for stakeholders to contest the terms of confidentiality agreements or establish the process for challenging the designation of information as confidential.

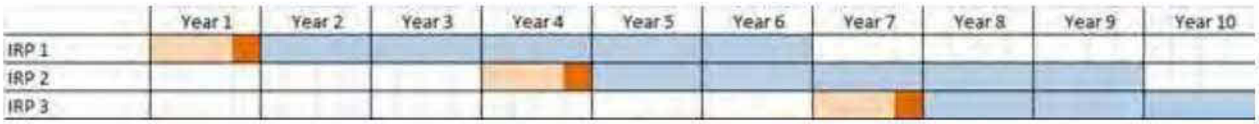
[30] *See* Ex. 2, P.R. Regs. CEEPR REG. §§ 1.15, 3.07; Ex. 6, Colo. Code Regs. § 723-3:3603(b). *See also* Ex. 2, Or. IRP at Guideline 2(b); Ex. 6, Colo. Code Regs. § 723-3:3604(j) (requiring the utility to provide MPSC with a list of information the utility considers to be confidential at the time of IRP submission); Ex. 6, Colo. Code Regs. § 723-3:3614.

[31] *See* Ex. 2, P.R. Regs. CEEPR REG. 9021 §§ 1.03, 1.05; Ex. 4, Or. IRP at Guideline 1(d).

[32] *See, e.g.*, Ex. 2, P.R. Regs. CEEPR REG. 9021 § 2.03(K).

processes. For example, in Colorado, utilities develop an IRP every four years, but develop an action plan (or resource acquisition period) of a 6- 10 year period.

Table 1



In addition, framing the action plan to specify anticipated need, rather than specific technologies, will enable utilities to act on the best-available, least-cost and least-risk resources to satisfy each need as it arises. Thus, the action plan should **not** be technology specific, although it may identify *anticipated* least-cost, least-risk resources. Although the utility will have conducted an all-source RFI as part of the IRP process, the RFI bids should only be used to inform preferred resource portfolios. When it's time to act on specific needs, the utility should conduct an all-source RFP. This process will ensure that (1) the IRP is based on accurate and current market information and (2) final, selected projects reflect any market shifts between when the utility completes its IRP and when the projected need actually arises.

For example, suppose the RFI results indicated a new wind facility might be the least-cost resource to satisfy a specific need anticipated in Year 4. The utility's action plan therefore identified wind as the anticipated resource, with construction anticipated to commence in Year 3 in order to be in service on time. Before beginning construction on the wind project in Year 3, however, the utility would conduct an all-source RFP to confirm whether wind was still the best resource. The RFP may show wind is still the best resource available, and the utility could use the resulting RFP wind bids to move forward with the wind project. On the other hand, the RFP might identify another resource, such as solar plus storage, to be cost-competitive.

Given the rapidly shifting market for energy resources, particularly renewables and energy storage, this approach will ensure resource decisions are grounded in accurate and up-to-date cost information. As with the all-source RFI used to inform the resource selection included within the IRP, these post-IRP RFPs should identify the specific needs to be satisfied while being technology-, size-, and location-neutral, including considering demand-side resources on equal footing as supply-side ones and not being limited to "dispatchable" resources.

IV. Conclusion

The Joint Stakeholders appreciate the proposal from Chairman Burns—it provides a strong foundation for developing an IRP rule that better serves the ratepayers and provides the kind of transparency needed for stakeholders and the Commission to better engage in and evaluate the utility plans. Many aspects of the Joint Stakeholder proposed rule can enhance and complement what the Chairman has proposed. We look forward to continuing to work on these important and complex issues.

Respectfully submitted on behalf of Sierra Club, Solar United Neighbors of Arizona, Southwest Energy Efficiency Project, Western Grid Group, Western Resource Advocates, and Vote Solar this 20th day of December, 2019.

/s/ Sandy Bahr

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Exhibit 1

TITLE 170 INDIANA UTILITY REGULATORY COMMISSION

Proposed Rule
LSA Document #12-xxx

DIGEST

Amends 170 IAC 4-7 to update the commission's rule requiring electric utilities to prepare and submit integrated resource plans. Effective 30 days after filing with the Publisher.

170 IAC 4-7-0.1
170 IAC 4-7-1
170 IAC 4-7-2
170 IAC 4-7-2.1
170 IAC 4-7-2.2
170 IAC 4-7-3
170 IAC 4-7-4
170 IAC 4-7-5
170 IAC 4-7-6
170 IAC 4-7-7
170 IAC 4-7-8
170 IAC 4-7-9
170 IAC 4-7-10

SECTION 1. 170 IAC 4-7-0.1 IS ADDED TO READ AS FOLLOWS

ARTICLE 4. ELECTRIC UTILITIES
Rule 7. Guidelines for Electric Utility Integrated Resource Plans

170 IAC 4-7-0.1 Applicability
Authority: IC 8-1-1-3
Affected: IC 8-1-2.2; IC 8-1-2.3-2; IC 8-1-2.4; IC 8-1-8.5; IC 8-1-8.8-10; IC 8-1.5

Sec. 0.1 (a) To assist the commission in its administration of the Utility Powerplant Construction Law, IC 8-1-8.5, this rule applies to the following electric utilities:
(1) Public investor owned.
(2) Municipally owned.
(3) Cooperatively owned.
(4) A joint agency created under IC 8-1-2.2. An individual member of a joint agency is not required to submit to the commission a separate IRP.
(b) This rule does not apply to a person who is exempt pursuant to IC 8-1-8.5-7.
(c) The following electric utilities are exempt from the public advisory process requirement in section 2.1 of this rule:
(1) Municipally owned.
(2) Cooperatively owned.
(3) A joint agency created under IC 8-1-2.2.

(Indiana Utility Regulatory Commission; 170 IAC 4-7-0.1)

SECTION 2. 170 IAC 4-7-1 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-1 Definitions

Authority: IC 8-1-1-3
Affected: IC 8-1-2.2; IC 8-1-2.3-2; IC 8-1-2.4; IC 8-1-8.5; IC 8-1-8.8-10; IC 8-1.5

Sec. 1. (a) **The definitions in this section apply throughout this rule.**

~~(a)~~ **(b)** ~~As used in this rule,~~ "Allowance" or "emission allowance" means the authority to emit one (1) ~~ton of sulfur dioxide (SO2), as defined under Section 7651 of the Clean Air Act Amendments of 1990, 42 U.S.C. 7401 to 7671q, effective November 15, 1990~~ **unit of any air pollutant as specified by a federal or state emission allowance system**.

~~(b) As used in this rule,~~ **(c)** "Avoided cost" means the amount of fuel, operation, maintenance, purchased power, labor, capital, taxes, and other cost not incurred by a utility if an alternative supply or demand-side resource is included in the utility's integrated resource plan.

~~(c) As used in this rule, "Clean Air Act Amendments of 1990" or "CAAA" means Title IV, Acid Deposition Control, of the federal Clean Air Act Amendments of 1990, 42 U.S.C. 7401 to 42 U.S.C. 7671q, in effect November 15, 1990.~~

(d) "Candidate resource portfolio" means a long-term resource mix selected through the utility's portfolio screening process to be further analyzed as necessary to determine the preferred resource portfolio.

~~(d) As used in this rule,~~ **(e)** "Cogeneration facility" means the following:

(1) A facility that simultaneously generates electricity and useful thermal energy and meets the energy efficiency standards established for a cogeneration facility by the Federal Energy Regulatory Commission (FERC) under 16 U.S.C. 824a-3, in effect November 9, 1978.

(2) The land, system, building, or improvement that is located at the project site and is necessary or convenient to the construction, completion, or operation of the facility.

(3) The transmission or distribution facility necessary to conduct the energy produced by the facility to a user located at or near the project site.

~~(e) As used in this rule,~~ **(f)** "Commission" means the Indiana utility regulatory commission.

~~(f) As used in this rule,~~ **(g)** "Conservation" means reducing the amount of energy consumed by a customer for a specific end-use. Conservation includes behavior changes such as thermostat setback. Conservation does not include changing the timing of energy use, switching to another fossil fuel source, or increasing off-peak usage.

(h) "Contemporary issues" means any topic that may affect the inputs, methods, or judgment factors in an IRP that is common to all Indiana jurisdictional utilities. Topics may include, but are not limited to, the following types of issues:

(1) Economic.
(2) Financial.
(3) Environmental.
(4) Energy.
(5) Demographic.
(6) Customer.

(7) Methodological.

(8) Regulatory.

(9) Technological.

(i) "Contemporary methods" means any methodological aspect involved with developing an IRP that represents the best practice of the electric industry to improve the quality of an IRP analysis.

~~(g) As used in this rule,~~ **(j)** "Demand-side management" or "DSM" means the planning, implementation, and monitoring of a utility activity designed to influence customer use of electricity that produces a desired change in a utility's load~~-shape~~. DSM includes only an activity that involves deliberate intervention by a utility to alter load~~-shape~~.

~~(h) As used in this rule,~~ **(k)** "Demand-side measure" means a particular end-use device, technology, service, or rate design at a targeted customer's premises or a utility's energy delivery system for a specific DSM program.

~~(i) As used in this rule,~~ **(l)** "Demand-side program" means a utility program designed to implement a demand-side measure.

~~(j) As used in this rule,~~ **(m)** "Demand-side resource" means a resource that reduces the demand for electrical power or energy by applying a demand-side program to implement one (1) or more demand-side measures.

(n) "Director" means the director of the electricity division of the commission.

~~(k) As used in this rule,~~ **(o)** "Discount rate" means the interest rate used in determining the present value of future cash flows.

~~(l) As used in this rule, "dispersed~~**(p) "Distributed** generation" means electric generation technology that is relatively small in size, and ~~its~~ **whose** implementation favors installation near a load center or remote location on the subtransmission or distribution system. **Distributed generation can include self-generation.**

~~(m) As used in this rule,~~ **(q)** "End-use" means the light, heat, cooling, refrigeration, motor drive, microwave energy, video or audio signal, computer processing, electrolytic process, or other useful work produced by equipment using electricity.

~~(n) As used in this rule,~~ **(r)** "Energy efficiency improvement" means reduced energy use for a comparable level of energy service.

~~(o) As used in this rule,~~ **(s)** "Energy service" means the light, heat, motor drive, and other service for which a customer purchases electricity from the utility.

~~(p) As used in this rule,~~ **(t) "Energy storage" means a:**

(1) technology; or

(2) set of technologies;

Capable of storing previously generated electric energy and discharging that energy as electricity at a later time.

(u) "Engineering estimate" means an estimate of energy (kWh) and demand (kW) impact resulting from a demand-side measure based on an engineering calculation procedure. An engineering estimate addresses change in energy use of a building or system resulting from installation of a DSM measure. If multiple DSM measures are installed, an engineering estimate accounts for the interactive effect between the DSM measures.

(v) "FERC Form 715" means the annual transmission planning and evaluation report required by the Federal Energy Regulatory Commission (FERC), as adopted in 58 FR 52436, Oct. 8, 1993, and as amended by Order 643, 68 FR 52095, Sept. 2, 2003.

~~(q) As used in this rule,~~ **(w)** "Firm wholesale power sale" means a power sale intended to be available to the purchaser at all times, including under adverse conditions, during the period covered by the commitment.

~~(r) As used in this rule, "hourly system lambda" means the change in a utility's total cost associated with a marginal change in hourly load. The hourly system lambda is a short run measure that reflects the change in fuel cost and includes incremental (or decremental) operation and maintenance expenses.~~

~~(s) As used in this rule,~~ **(x)** "Integrated resource ~~planning", "~~plan" or "IRP" means a utility's ~~assessment of a variety of demand-side and supply-side resources to cost-effectively meet customer electricity service needs. The IRP may also include, but is not limited to, the following:~~

~~(1) A public participation procedure.~~

~~(2) An analysis of the uncertainty and risk posed by different resources and external factors~~ **document submitted in order to meet the requirements of this rule**.

~~(t) As used in this rule,~~ **(y)** "Load building" means a program intended to increase electricity consumption without regard to the timing of the increased usage.

~~(u) As used in this rule,~~ **(z)** "Load research" means the collection of electricity usage data through a metering device associated with an end-use, a circuit, or a building. The metered data is used to better understand the characteristics of electric loads, the timing of their use, and the amount of electricity consumed by users. The data may be collected over a variety of time intervals, usually sixty (60) minutes or less.

~~(v) As used in this rule,~~ **(aa)** "Load shape" means the time pattern of customer electricity use and the relationship of the level of energy use to a specific time during the day, month, and year.

~~(w) As used in this rule, "Lost opportunity" means a situation where a cost-effective demand-side measure could have been installed at a site during construction, renovation, or replacement of equipment, but was not, rendering a subsequent equal or more extensive modification to the site not cost-effective.~~

~~(x) As used in this rule,~~ **(bb)** "Non-utility generator" or ~~"NUG"~~ means a facility for generating electricity that:

(1) is not exclusively owned by a public utility;

(2) operates connected to an electric utility system; and

(3) sells electricity to a utility for resale to retail customers.

(cc) "North American industrial classification system" or "NAICS" means a system developed by the United States Department of Commerce for use in the classification of establishments by type of activity in which engaged, for purposes of facilitating the collection, tabulation, presentation and analysis of data relating to establishments, and for promoting uniformity and comparability in the presentation of statistical data collected by various agencies of the United States Government, state agencies, trade associations, and private research organizations.

~~(y) As used in this rule,~~ **(dd)** "Participant" means a utility customer participating in a utility-sponsored DSM program.

~~(z) As used in this rule,~~ **(ee)** "Participant test" means a cost-effectiveness test that measures the difference between the cost incurred by a participant in a demand-side program and the value received by the participant. A participant's cost includes all costs borne by the participant. A participant's value from a DSM program consists of only the direct economic benefit received by the participant.

~~(aa) As used in this rule,~~ **(ff)** "Penetration" means the ratio of the number of a specific type of new units installed to the total number of new units installed during a given time.

(gg) "Power transfer capability" means the amount of power that can be transferred from one point or part of the bulk electric system to another without exceeding any reliability criteria pertinent to the utility.

(hh) "Preferred resource portfolio" means the utility's selected long-term resource mix that safely and reliably meets electric system demand, taking cost, risk, and uncertainty into consideration.

~~(bb) As used in this rule,~~ **(ii)** "Present value" means today's value of a future payment, or stream of payments, discounted at some appropriate compound interest or discount rate.

~~(cc) As used in this rule,~~ **(jj)** "Program cost" means all expenses incurred by a utility in a given year for operation of a DSM program whether the cost is capitalized or expensed. An expense includes, but is not limited to, the following:

(1) Administration.

(2) Equipment.

(3) Incentives paid to program participants.

(4) Marketing and advertising.

(5) Monitoring and evaluation.

~~(dd) As used in this rule,~~ **(kk)** "Public ~~participation~~ **advisory process**" means ~~a procedure~~ **the procedures referenced in section 2.1 of this rule** ~~where a customer or interested party is provided~~ **in which customers and interested parties have** the opportunity to **receive information and provide input for the utility to consider in the development of the IRP and** comment on a utility's ~~integrated resource plan~~**IRP** prior to the submission of the IRP to the commission.

~~(ee) As used in this rule,~~ **(ll)** "Ratepayer impact measure" or "RIM" test means a cost-effectiveness test which analyzes how a rate for electricity is altered by implementing a DSM program. This test measures the change in a revenue requirement expressed on a per unit of sale basis.

(mm) "Regional transmission organization" or "RTO" means the regional transmission organization approved by the Federal Energy Regulatory Commission for the control area that includes the utility's assigned service area (as defined in IC 8-1-2.3-2).

~~(ff) As used in this rule,~~ **(nn)** "Renewable resource" means a ~~generation facility or technology utilizing a fuel source such as, but not limited to, the following:~~

~~(1) Wind.~~

~~(2) Solar.~~

~~(3) Geothermal.~~

~~(4) Waste.~~

~~(5) Biomass.~~

~~(6) Small hydro.~~

renewable energy resource as defined in IC 8-1-8.8-10.

~~(gg) As used in this rule,~~ **(oo)** "Resource" means a facility, project, contract, or other mechanism used by a utility to provide electric energy service to the customer.

(pp) "Resource action" means a resource change or addition proposed by a utility in a formally docketed proceeding.

(qq) "Risk metric" means a measure used to gauge the risk associated with a resource portfolio. As applied to the cost of a resource portfolio, this includes measures of the variability of costs and the magnitude of outcomes.

~~(hh) As used in this rule,~~ **(rr)** "Saturation" means the ratio of the number of a specific type of similar appliance or equipment to the total number of customers in that class or the total number of similar appliances or equipment in use.

~~(ii) As used in this rule,~~ **(ss)** "Screening" means an evaluation performed by a utility to determine whether a demand-side or supply-side resource option is eligible for potential inclusion in the utility's ~~integrated resource plan~~**preferred resource portfolio**.

~~(jj) As used in this rule,~~ **(tt)** "Self-generation" means an electric generation facility primarily for the customer's own use and not for the primary purpose of producing electricity, heat, or steam for sale to or for the public for compensation.

~~(kk) As used in this rule,~~ **(uu)** "Short term action plan" means a schedule of activities and goals developed by a utility to begin efficient implementation of its ~~integrated resource plan~~**preferred resource portfolio**.

(vv) "Smart grid" means use of digital electronics or data, and the associated communications networks, to monitor and control any aspects of the electrical transmission and distribution system from generation to consumption.

~~(ll) As used in this rule, "standard industrial classification" or "SIC" means a system developed by the United States Department of Commerce for use in the classification of establishments by type of activity in which engaged, for purposes of facilitating the collection, tabulation, presentation and analysis of data relating to establishments, and for promoting uniformity and comparability in the presentation of statistical data collected by various agencies of the United States Government, state agencies, trade associations, and private research organizations.~~

~~(mm) As used in this rule,~~ **(ww)** "Supply-side resource" means a resource that provides a supply of electrical energy or capacity, or both, to a utility. A supply-side resource **may** include the following:

(1) A utility-owned generation capacity addition.

(2) A wholesale power purchase from another utility or non-utility generator.

(3) A refurbishment or upgrading of an existing utility-owned generating facility.

(4) A cogeneration facility.

(5) A renewable resource technology.

(6) Distributed generation.

~~(nn) As used in this rule,~~ **(xx)** "Targeted demand-side management" or "targeted DSM" means a demand-side program designed to defer or eliminate investment in a transmission or distribution facility.

~~(oo) As used in this rule,~~ **(yy)** "Total resource cost test" means a cost-effectiveness test that eliminates the distinction between a participant and nonparticipant by analyzing whether a resource is cost-effective based on the total cost and benefit of the program, independent of the precise allocation to a shareholder, ratepayer, and participant.

~~(pp) As used in this rule,~~ **(zz)** "Utility" means:

(1) a public, municipally owned, or cooperatively owned utility; or

(2) a joint agency created under IC 8-1-2.2.

~~(qq) As used in this rule,~~ **(aaa)** "Utility cost test" or "revenue requirements test" means a cost-effectiveness test designed to ~~minimize~~ **measure the ratio of the benefits (to the utility) to the costs incurred by the utility** (~~the net present value of a utility's~~ revenue requirements). *(Indiana Utility Regulatory Commission; 170 IAC 4-7-1; filed Aug 31, 1995, 9:00 a.m.: 19 IR 16; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA)*

SECTION 3. 170 IAC 4-7-2 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-2 Procedures and effects of filing integrated resource plans

Authority: IC 8-1-1-3

Affected: IC 5-14-3; IC 8-1-1-8; IC 8-1-8.5; IC 8-1.5

Sec. 2. (a) **The following utilities, or their successors in interest, must submit to the commission an IRP that covers at least a 20 year planning horizon consistent with this rule according to the following schedule**:

(1) Duke Energy Indiana, Indiana Michigan Power Company, Indiana Municipal Power Agency, and Wabash Valley Power Association on November 1, 2013, and biennially thereafter.

(2) Hoosier Energy Rural Electric Cooperative, Indianapolis Power and Light Company, Northern Indiana Public Service Company, and Southern Indiana Gas and Electric Company on November 1, 2014, and biennially thereafter.

Upon request of a utility, the director may grant an extension of any such submission dates, for good cause shown.

(b) Prior to constructing, purchasing, or leasing a generating facility to provide electric service within the state of Indiana, a utility not listed in subsection (a) must submit to the commission an IRP consistent with this rule. If the generating facility, after appropriate commission review, is constructed, purchased, or leased, the utility shall submit to the commission on a biennial basis, an IRP consistent with this rule.

(c) A utility subject to section 0.1 must submit to the commission, on or before the applicable date as specified in subsection (a), the following documents:

(1) The integrated resource plan.

(2) A technical appendix containing supporting documentation.

(3) An IRP summary document as described in section 4(a) of this rule.

(d) The documents listed in subsection (c) shall be submitted electronically to the director.

~~The commission may use an IRP or written comments, or both, submitted pursuant to this rule, to assist in the preparation of an analysis of the long range needs for expansion of facilities for the generation of electricity and plan for meeting the future requirements of electricity as required by IC 8-1-8.5. The commission may also use the IRP or written comments, or both, submitted pursuant to this rule in the preparation of a staff report in other formally docketed proceedings.~~

~~(1) An IRP or written comments submitted to the commission pursuant to this rule may be admitted as evidence in a formally docketed proceeding before the commission under the Indiana Rules of Evidence:~~

~~(2) The commission shall give such weight as it determines appropriate to any IRP, or written comments submitted to the commission thereon, admitted as evidence in a formally docketed proceeding as provided in subsection 2(a)(1) *[subdivision (1)]* above.~~
~~(3) An IRP or comments submitted pursuant to this rule may not be admitted as evidence in a formally docketed proceeding before the commission through use of 170 IAC 1-1-18(f).~~

~~(b) Notice of the submission of an IRP to the commission shall be provided pursuant to the publication requirements of IC 8-1-1-8.~~

~~(c)~~**(e)** Contemporaneously with the submission of an IRP to the commission, a utility must include the following information:

(1) The name and address, if known, of each individual or entity considered by the utility to be an interested party.

(2) A statement that the utility has sent each interested party, **electronically or** by deposit in the United States mail, First Class postage prepaid, a notice of the utility's submission of an IRP to the commission. The notice must contain, at a minimum, the following information:

(A) A general description of the subject matter of the submitted IRP.

(B) A statement that the commission invites an interested party to submit written comment on the utility's submitted IRP.

(C) A statement that ~~the commission will provide notice of the IRP and the due date for the submission of written comments pursuant to the publication requirements of IC 8-1-1-8. The statement must also include that~~ subsection ~~(e)~~ **(g)** below provides for a ninety(90) day time period~~, or longer as determined by the commission,~~ to submit written comments.

A utility is not required to separately notice, as provided in this subsection, each of its customers. A utility may, however, individually notify a business, organization, or a particular customer having a substantial interest in the IRP.

(3) A statement that the utility has served a copy of the IRP on the office of the consumer counselor.

~~(d) An IRP submitted to~~ **(f)** The commission **shall make a submitted IRP available:**

(1) on its website; and

(2) ~~may~~ **to** be viewed, inspected, or copied, ~~in accordance with IC 5-14-3,~~ at the office of the commission at 101 West Washington Street, Suite 1500 E, Indianapolis, Indiana 46204**;**

in accordance with IC 5-14-3 and any determination by the commission regarding confidentiality under 170 IAC 1-1.1-4.

~~(e)~~**(g)** A customer or interested party may comment on an IRP submitted to the commission. The comments must:

(1) be in writing**;**

(2) ~~and~~ received by the commission within ninety (90) days from the date a utility submits an IRP to the commission~~. A customer or interested party must~~;

~~(1) submit~~ **(3) be submitted** to the commission:

(A) as a paper original at the address provided in subsection ~~(d)~~**(f); or**

(B) ~~an original and eight (8) copies of the written comments~~ **electronically to the director**;

~~(2)~~ **(4)** clearly identify the utility upon which written comments are submitted; and

~~(3) when submitting written comments on an IRP, serve a copy of the comments~~ **(4) be served** upon the utility.

The ~~commission~~ **director** may extend the filing deadline for submitting written comments.

~~(f)~~**(h) The director shall issue a draft report on the IRP no later than 120 days from the date a utility submits an IRP to the commission.**

(i) ~~Upon the receipt of written comments of a customer or interested party, a utility may submit to the commission supplemental or response comments.~~ **Supplemental or response comments may be submitted by:**

(1) the utility; or

(2) any customer or interested party that submitted written comments.

(j) Supplemental or response comments must be:

(1) in writing; ~~and~~

(2) received by the commission within thirty (30) days from the date ~~a customer or interested party submits comments to the commission. A utility must~~;

~~(1) submit~~ **the director issues the draft report;**

(3) submitted to the commission, ~~at the address provided in subsection (d) an original and eight (8) copies of the written comments~~ **electronically to the director**~~an original and eight (8) copies of the supplemental or response comments~~; and;

~~(2) serve a copy of the supplemental or response comments~~ **(4) served** upon:

(A) the utility;

(B) ~~the~~ **any** customer or interested party who submitted written comments; and

(B) the office of the **utility** consumer counselor.

The ~~commission~~ **director** may extend the filing deadline for submitting supplemental or response comments.

~~(g)~~**(i)** The ~~commission~~ **director** may allow additional written comment periods.

(j) The director shall issue a final report on the IRP within 30 days following the deadline for supplemental or response comments.

(k) The draft report and the final report shall be limited to the:

(1) informational;

(2) procedural; and

(3) methodological

requirements of this rule.

(l) The draft report and final report shall not comment on:

(1) the utility's preferred resource plan; or

(2) any resource action chosen by the utility.

(m) Upon appropriate notice to the utility and interested parties, the director may extend the deadlines for issuance of the draft report and the final report.

(n) Failure by the director to issue a draft or final report shall result in a presumption that the IRP complies with this rule.

(o) The following documents shall be made available on the commission's website:

(1) Written comments.

(2) Responsive comments.

(3) The draft report.

(4) The final report.

~~(h)~~**(p)** The failure of an interested party to file comments ~~pursuant to subsection (e)~~ **under this rule** shall not constitute a waiver of any right to participate as a party or to advance any argument or position in a formally docketed proceeding before the commission. Similarly, the content of comments filed by an interested party under ~~subsection (e)~~ **this rule** shall not estop or preclude that party from advancing any argument or position in a formally docketed proceeding before the commission, whether or not that argument or position was raised in comments submitted under ~~subsection (e)~~**this rule**.

(q) Any resource action shall be consistent with the most recent IRP submitted under this rule, including its:

(1) inputs (including data and assumptions):

(2) methods (including models); and

(3) judgment factors (including the rationales used to determine inputs, methods, and risk metric(s));

unless any discrepancies between the most recent IRP and the resource action are fully explained and justified with supporting evidence, including updated IRP analyses.

(r) Documents submitted or created pursuant to this rule may be used as follows:

(1) To assist the commission in the preparation of an analysis of the long range needs for expansion of facilities for the generation of electricity and plan for meeting the future requirements of electricity as required by IC 8-1-8.5.

(2) In the preparation of a commission staff report in formally docketed proceedings before the commission.

(3) Submitted as evidence in a formally docketed proceeding before the commission. The commission shall give such weight as it determines appropriate to such evidence.

(Indiana Utility Regulatory Commission; 170 IAC 4-7-2; filed Aug 31, 1995, 9:00 a.m.:19 IR 18; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA; errata filed Jul 21, 2009, 1:33 p.m.: 20090819-IR-170090571ACA)

SECTION 4. 170 IAC 4-7-2.1 IS ADDED TO READ AS FOLLOWS:

170 IAC 4-7-2.1 Public advisory process

Authority: IC 8-1-1-3

Affected: IC 8-1-8.5

Sec. 2.1 (a) The utility shall have a public advisory process as outlined in this section.

(b) The utility shall:

(1) provide information to; and

(2) solicit and consider relevant input from;

any interested party in regard to the development of the utility's IRP and related potential resource acquisition issues.

(c) The utility shall consider and respond to all relevant input provided by interested parties, including comments and concerns from the commission or its staff.

(d) The utility retains full responsibility for the content of its IRP.

(e) The public advisory process shall be administered as follows:

(1) The utility shall initiate and convene its own public advisory process. The utility will hold at least:

(A) one introductory meeting; and

(B) one meeting regarding its preferred resource portfolio;

before submittal of its IRP to the commission.

(2) Depending on the level of interest by commission staff, the public and interested parties in the utility's public advisory process, the utility may hold additional meetings.

(3) The utility shall take reasonable steps:

(A) to notify its customers and the commission of its public advisory process; and

(B) provide notification to known interested parties.

(4) The timing of meetings shall be determined by the utility:

(A) to be consistent with its internal IRP development schedule; and

(B) to provide an opportunity for public participation in a timely manner that may affect the outcome of the utility resource planning efforts.

(5) The utility or its designee shall:

(A) chair the participation process;

(B) schedule meetings; and

(C) develop agendas for those meetings.

Participants are allowed to request that relevant items be placed on the agenda of the meetings if they provide adequate notice to the utility.

(6) Topics discussed in the public advisory process shall include, but are not limited to, the following:

(A)The utility's load forecast.

(B) Evaluation of existing resources.

(C) Evaluation of supply and demand side resource alternatives, including:

(i) associated costs; and

(ii) performance attributes.

(D) Modeling methods.

(E) Modeling inputs.

(F) Treatment of risk and uncertainty.

(G) Rationale for determining the preferred resource portfolio.

(Indiana Utility Regulatory Commission; 170 IAC 4-7-2.1)

SECTION 5. 170 IAC 4-7-2.2 IS ADDED TO READ AS FOLLOWS:

170 IAC 4-7-2.2 Contemporary issues technical conference

Authority: IC 8-1-1-3

Affected: IC 8-1-8.5

Sec. 2.2 (a) The commission or its staff may host an annual technical conference to help identify contemporary issues and encourage the identification and adoption of best practices to manage such issues.

(b) The technical conference may also identify a standardized reporting format.

(c) The agenda of the technical conference shall be set by the commission staff that includes input from interested parties and utilities. Utilities and interested parties may petition or informally contact the commission staff to request the inclusion of specific contemporary issues.

(d) The director may provide guidance concerning specific contemporary issues for a utility to address in its next IRP filing. The director shall provide utilities with a written summary of the issues to be addressed. The utility shall, to the extent possible, provide either a discussion of the impacts of such issues on its IRP or demonstrate how it has taken such issues into account.

(e) The contemporary issues technical conference shall take place at least one (1) year prior to the filing date of a utility's IRP.

(Indiana Utility Regulatory Commission; 170 IAC 4-7-2.2)

SECTION 6. 170 IAC 4-7-3 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-3 Waiver or variance requests

Authority: IC 8-1-1-3

Affected: IC 5-14-3; IC 8-1-2-29; IC 8-1-2.2; IC 8-1-8.5-7; IC 8-1.5

Sec. 3. (a) ~~To assist the commission in its administration of the Utility Powerplant Construction Law, IC 8-1-8.5, this rule applies to the following:~~

~~(1) A public, municipally owned, or cooperatively owned utility.~~

~~(2) A joint agency created under IC 8-1-2.2. An individual member of a joint agency is not required to submit to the commission a separate integrated resource plan.~~

~~(b) This rule does not apply to a person who is exempt pursuant to IC 8-1-8.5-7.~~

~~(c) A utility operating or owning, in part or whole, an electrical generating facility as of January 1, 1995, to provide electric service within the state of Indiana must submit to the commission on a biennial basis, beginning on or before November 1, 1995, an integrated resource plan consistent with this rule. Upon request of a utility, the commission may grant an extension of any such submission dates, for good cause shown.~~

~~(d) A utility not subject to subsection (c) prior to constructing, purchasing, or leasing a generating facility to provide electric service within the state of Indiana must submit to the commission an integrated resource plan consistent with this rule. If the generating facility, after appropriate commission review, is constructed, purchased, or leased, the utility shall submit to the commission on a biennial basis, an integrated resource plan consistent with this rule.~~

~~(e) A utility subject to subsection (a) must submit to the commission, on or before the applicable date as specified in subsection (c) or (d), the following documents:~~

~~(1) The integrated resource plan.~~

~~(2) A technical appendix containing supporting documentation.~~

~~(f) If a utility considers information in the IRP or technical appendix to be proprietary or otherwise confidential, a utility must file concurrently a redacted version, a nonredacted version under seal which shall be treated as confidential pending completion of the proceeding described below, verified affidavits from appropriate representatives of the utility setting forth the reasons why the information is proprietary or otherwise confidential, and a petition requesting that the commission find that such information is confidential pursuant to IC 8-1-2-29 and IC 5-14-3. A~~

~~customer or interested party seeking access to or desiring to contest a commission determination regarding information claimed by a utility to be proprietary and confidential may do so only through intervention and participation in the proceeding on the utility petition requesting a finding of confidentiality. If, after review, the commission determines the information is proprietary or confidential, the commission and its staff will treat the information as proprietary or confidential in accordance with IC 8-1-2-29 and IC 5-14-3.~~ **The utility may request a waiver or a variance from a provision of this rule for good cause shown in advance of a filing date.**

(1) The request shall include:

(A) A description of the situation which necessitates the waiver or variance.

(B) Identification of the provision(s) of this rule for which the waiver or variance is requested.

(C) Explanation of the difference between the expected effects of complying with this rule on the utility, its customers, and participants in the public advisory process if the waiver or variance is not granted and the expected effect on such parties if granted.

(D) Explanation of how the waiver or variance is expected to aid or, at the least, not undermine the procedures and requirements of this rule.

(2) The request shall be submitted in sufficient time that the IRP submittal schedule shall not be adversely affected.

(b) The director shall respond in writing regarding acceptance or denial of a request under this section within fifteen (15) days. The request shall not be unreasonably denied, but any denials shall include the reason for the denial. If the director fails to respond within fifteen (15) days, the request shall be deemed accepted.

(c) The request by the utility and the director's acceptance or denial shall be posted on the commission's website.

(d) An appeal to the full commission of the director's acceptance or denial under this section must be filed with the commission within thirty (30) days of the posting of the director's written acceptance or denial of the request.

(Indiana Utility Regulatory Commission; 170 IAC 4-7-3; filed Aug 31, 1995, 9:00 a.m.: 19 IR 19; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA)

SECTION 7. 170 IAC 4-7-4 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-4 Methodology and documentation requirements

Authority: IC 8-1-1-3; IC 8-1-8.5

Affected: IC 8-1; IC 8-1.5

Sec. 4. **(a) The utility shall provide an IRP summary document that communicates core IRP concepts and results to non-technical audiences.**

(1) The summary shall provide a brief description of the utility's existing resources, preferred resource portfolio, short term action plan, key factors influencing the preferred resource portfolio and short term action plan, and any additional details the commission staff may request as part of a contemporary issues meeting. The summary shall describe, in simple terms, the IRP public advisory process, if

applicable, and core IRP concepts, including resource types and load characteristics.

(2) The utility shall utilize a simplified format that visually portrays the summary of the IRP in a manner that makes it understandable to a non-technical audience.

(3) The utility shall make this document readily accessible on its website.

(b) An IRP ~~covering at least a twenty (20) year future period prepared by a utility~~ must include **the following:**

(1) A discussion of the:

(A) inputs;

(B) methods ~~data, assumptions~~; and

(C) definitions;

used ~~in developing~~ **by the utility in** the IRP ~~and the goals and objectives of the plan. The following information must be included:~~.

~~(1)~~ **(2)** The data sets, including data sources, used to establish base and alternative forecasts. A third party data source may be ~~presented in the form of a reference~~**referenced**. The reference must include the source title, author, publishing address, date, and page number of relevant data. The data sets must include an explanation for adjustments. The data must be provided on electronic media, and may be submitted as a file separate from the IRP , or as specified by the commission.

~~(2)~~**(3)** A description of the utility's effort to develop and maintain **a data base of electricity consumption patterns**, by customer class, rate class, ~~SIC~~ **NAICS** code, and end-use~~, a data base of electricity consumption patterns~~. The data base may be developed using, but not limited to, the following methods:

(A) Load research developed by the individual utility.

(B) Load research developed in conjunction with another utility.

(C) Load research developed by another utility and modified to meet the characteristics of that utility.

(D) Engineering estimates.

(E) Load data developed by a non-utility source.

~~(3)~~**(4)** A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on end-use appliance penetration, end-use saturation rates, and end-use electricity consumption patterns.

~~(4)~~**(5)** A discussion of ~~customer self-generation~~ **distributed generation** within the service territory and the potential effects on generation, transmission, and distribution planning and load forecasting.

~~(5) A description of model structure and an evaluation of model performance.~~

(6) A complete discussion of the alternative forecast scenarios developed and analyzed, including a justification of the assumptions and modeling variables used in each scenario.

(7) A ~~description~~ **discussion** of **how** the **utility's** fuel inventory and procurement planning practices, ~~including the rationale, used in the development of the utility's integrated resource plan~~**have been taken into account and influenced the IRP development**.

(8) A ~~description~~ **discussion** of **how** the ~~SO2~~ **utility's** emission allowance inventory and procurement ~~planning~~ practices **for any air emission regulated through an emission allowance system have been taken into account and influenced the IRP development** ~~including the rationale, used in the development of the utility's integrated resource plan~~.

(9) A description of the generation expansion planning criteria ~~used in developing the IRP~~. The description must fully explain the basis for the criteria selected~~, including an analysis and rationale for the level of system wide generation reliability assumed in the IRP~~.

(10) ~~A regional, or at a minimum, Indiana specific power flow study prepared by a regional or subregional organization. This requirement may be met by submitting Federal Energy Regulatory Commission (FERC) Form 715, as adopted in Docket No. RM93-10-00, in effect October 30, 1993. The power flow study shall include the following:~~

~~(A) Solved real flows.~~

~~(B) Solved reactive flows.~~

~~(C) Voltages.~~

~~(D) Detailed assumptions.~~

~~(E) Brief description of the model(s).~~

~~(F) Glossary of terms with cross references to the names of buses and line terminals.~~

~~(G) Sensitivity analysis, including, but not limited to, the forecast of the following:~~

~~(i) Summer and winter peak conditions.~~

~~(ii) Light load as well as heavy transfer conditions for one (1), two (2), five (5), and ten (10) years out.~~

~~(iii) Branch circuit ratings, including, but not limited to, normal, long term, short term, and emergency.~~

~~(11) Any recent dynamic stability study prepared for the utility or by the utility. This requirement may be met by submitting FERC Form 715, as adopted in Docket No. RM93-10-00, in effect October 30, 1993~~ **A brief description and discussion within the body of the IRP focusing on the utility's Indiana jurisdictional facilities with regard to the following components of FERC Form 715:**

(A) Most current power flow data models, studies, and sensitivity analysis.

(B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. The simulation must include the capability of meeting the standards of the North American Electric Reliability Corporation (NERC).

(C) Reliability criteria for transmission planning as well as the assessment practice used. The information and discussion must include the limits set of its transmission use, its assessment practices developed through experience and study, and certain operating restrictions and limitations particular to it.

(D) Various aspects of any joint transmission system, ownership, and operations and maintenance responsibilities as prescribed in the terms of the ownership, operation, maintenance, and license agreement.

~~(12) Applicable transmission maps,. This requirement may be met by submitting FERC Form 715, as adopted in Docket No. RM93-10-00, in effect October 30, 1993.~~

~~(13)~~**(11)** ~~A description of reliability criteria for transmission planning as well as the assessment practice used. This requirement may be met by submitting FERC Form 715, as adopted in Docket No. RM93-10-00, in effect October 30, 1993.~~**An explanation of**

the contemporary methods utilized by the utility in developing the IRP, including a description of the following:

(A) Model structure and reasoning for use of particular model or models in the utility's IRP.

(B) The utility's effort to develop and improve the methodology and inputs for its:

(i) forecast;

(ii) cost estimates;

(iii) treatment of risk and uncertainty; and

(iv) evaluation of a resource (supply-side or demand-side) alternative's contribution to system wide reliability. The measure of system wide reliability must cover the reliability of the entire system, including:

(AA) transmission; and

(BB) generation.

~~(14) An evaluation of the reliability criteria in relation to present performance and the expected performance of the utility's transmission system. This requirement may be met by submitting FERC Form 715, as adopted in Docket No. RM93-10-00, in effect October 30, 1993.~~

~~(15) A description of the utility's effort to develop and improve the methodology and the data for evaluating a resource (supplyside or demand-side) option's contribution to system wide reliability. The measure of system wide reliability must cover the reliability of the entire system, including transmission, distribution, and generation.~~

~~(16)~~**(12)** An explanation, with supporting documentation, of the avoided cost calculation. An avoided cost must be calculated for each year in the forecast period. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. Avoided cost shall include, but is not limited to, the following:

(A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement.

(B) The avoided transmission capacity cost.

(C) The avoided distribution capacity cost.

(D) The avoided operating cost, including fuel, plant operation and maintenance, spinning reserve, emission allowances, and transmission and distribution operation and maintenance.

~~(17)~~**(13)** The ~~hourly system lambda and the~~ actual demand for all hours of the most recent historical year available**, which shall be submitted electronically and may be a separate file from the IRP**. For purposes of comparison, a utility must maintain three (3) years of hourly data~~and the corresponding dispatch logs~~.

~~(18)~~**(14)** ~~A description~~ **Publicly owned utilities shall provide a summary** of the utility's:

(A) most recent public ~~participation procedure if the utility conducts a procedure prior to the submission of an IRP to the commission~~ **advisory process;**

(B) key issues discussed; and

(C) how they were addressed by the utility.

(Indiana Utility Regulatory Commission; 170 IAC 4-7-4; filed Aug 31, 1995, 9:00 a.m.: 19 IR 20; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA)

SECTION 8. 170 IAC 4-7-5 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-5 Energy and demand forecasts

Authority: IC 8-1-1-3
Affected: IC 8-1-8.5; IC 8-1.5

Sec. 5. (a) An electric utility subject to this rule shall prepare an analysis of historical and forecasted levels of peak demand and energy usage which includes the following:

(1) ~~An~~ Historical ~~and projected analysis of a variety of~~ load shapes, including, but not limited to, the following:

(A) Annual load shapes.
(B) Seasonal load shapes.
(C) Monthly load shapes.
(D) Selected weekly and daily load shapes. Daily load shapes shall include, at a minimum, summer and winter peak days and a typical weekday and weekend day.

(2) Historical and projected load shapes shall be disaggregated, to the extent possible, by customer class, interruptible load, and end-use and demand-side management program.
(3) Disaggregation of historical data and forecasts by customer class, interruptible load, and end-use where information permits.
(4) ~~The use and reporting of~~ Actual and weather normalized energy and demand levels.
(5) A discussion of all methods and processes used to normalize for weather.
(6) A **minimum** twenty (20) year period for energy and demand forecasts.
(7) An evaluation of the performance of energy and demand forecasts for the previous ten (10) years, including, but not limited to, the following:

(A) Total system.
(B) Customer classes or rate classes, or both.
(C) Firm wholesale power sales.

(8) ~~If an end use methodology has not been used in forecasting, an explanation as to why this methodology has not been used.~~ **Justification for the selected forecasting methodology.**
(9) For purposes of ~~section 5(a)(1) and 5(a)(2)~~ ~~*[subdivisions (1) and (2)]*~~ **subdivisions (1) and (2)**, a utility may use utility specific data or more generic data, such as, but not limited to, the types of data described in section ~~4(2)~~ **4(b)(2)** of this rule.

(b) A utility shall provide at least three (3) alternative forecasts of peak demand and energy usage. At a minimum, the utility shall include high, low, and most probable energy and peak demand forecasts based on ~~combinations of~~ alternative assumptions such as:

(1) Rate of change in population.
(2) Economic activity.
(3) Fuel prices.
(4) Changes in technology.
(5) Behavioral factors affecting customer consumption.
(6) State and federal energy policies.

(7) State and federal environmental policies.
(Indiana Utility Regulatory Commission; 170 IAC 4-7-5; filed Aug 31, 1995, 9:00 a.m.: 19 IR 21; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA)

SECTION 9. 170 IAC 4-7-6 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-6 Resource assessment

Authority: IC 8-1-1-3
Affected: IC 8-1-8.5; IC 8-1.5

Sec. 6. (a) ~~For each year of the planning period, excluding subsection 6(a)(6) *[subdivision (6)]*, recognizing the potential effects of self generation, an electric~~ **The utility shall consider continued use of an existing resource as a resource alternative in meeting future electric service requirements. The** utility shall provide a description of the utility's **existing** electric power resources that must include, at a minimum, the following information:

(1) The net dependable generating capacity of the system and each generating unit.
(2) The expected changes to existing generating capacity, including, but not limited to, the following:
(A) Retirements.
(B) Deratings.
(C) Plant life extensions.
(D) Repowering.
(E) Refurbishment.
(3) A fuel price forecast by generating unit.
(4) The significant environmental effects, including:
(A) air emissions;
(B) solid waste disposal;
(C) hazardous waste; and
(D) subsequent disposal; **and**
(E) water consumption and discharge;
at each existing fossil fueled generating unit.
(5) ~~The scheduled power import and export transactions, both firm and nonfirm, as well as cogeneration and non-utility production expected to be available for purchase by the utility.~~
~~(6)~~ An analysis of the existing utility transmission system that includes the following:
(A) An evaluation of the adequacy to support load growth and ~~long term power purchases and sales~~**expected power transfers**.
(B) An evaluation of the supply-side resource potential of actions to reduce transmission losses**, congestion, and energy costs**.
(C) An evaluation of the potential impact of demand-side resources on the transmission network.
(D) An assessment of the transmission component of avoided cost.
~~(7)~~**(6)** A discussion of demand-side programs, including existing company-sponsored and government-sponsored or mandated energy conservation or load management programs

available in the utility's service area and the estimated impact of those programs on the utility's historical and forecasted peak demand and energy.

The information listed above in subdivision (a)(1) through subdivision (a)(4) and in subdivision (a)(6) shall also be provided for each year of the planning period.

(b) An electric utility shall consider alternative methods of meeting future demand for electric service. A utility must consider a demand-side resource, including innovative rate design, as a source of new supply in meeting future electric service requirements. The utility shall consider a comprehensive array of demand-side measures that provide an opportunity for all ratepayers to participate in DSM, including low-income residential ratepayers. For a utility-sponsored program identified as a potential demand-side resource, the utility's ~~plan~~ **IRP** shall, at a minimum, include the following:

(1) A description of the demand-side program considered.

(2) ~~A detailed account of utility strategies designed to capture lost opportunities.~~

~~(3)~~ The avoided cost projection on an annual basis for the forecast period that accounts for avoided generation, transmission, and distribution system costs. The avoided cost calculation must reflect timing factors specific to resources under consideration such as project life and seasonal operation.

~~(4)~~**(3)** The customer class or end-use, or both, affected by the program.

~~(5)~~**(4)** A participant bill reduction projection and participation incentive to be provided in the program.

~~(6)~~**(5)** A projection of the program cost to be borne by the participant.

~~(7)~~**(6)** Estimated energy (kWh) and demand (kW) savings per participant for each program.

~~(8)~~**(7)** The estimated program penetration rate and the basis of the estimate.

~~(9)~~**(8)** The estimated impact of a program on the utility's load, generating capacity, and transmission and distribution requirements.

(c) A utility shall consider **a range of** supply-side resources **including cogeneration and non-utility generation** as an alternative in meeting future electric service requirements. **This range shall include commercially available resources or resources the director may request as part of a contemporary issues technical conference.** The utility's ~~plan~~ **IRP** shall include, at a minimum, the following:

(1) Identify and describe the resource considered, including the following:

(A) Size (MW).

(B) Utilized technology and fuel type.

(C) Additional transmission facilities necessitated by the resource.

(2) ~~Significant environmental effects, including the following:~~

~~(A) Air emissions.~~

~~(B) Solid waste disposal.~~

~~(C) Hazardous waste and subsequent disposal.~~

~~(3) An analysis of how a proposed generation facility conforms with the utility-wide plan to comply with the Clean Air Act Amendments of 1990.~~

~~(4)~~ A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost.

(d) A utility shall ~~identify~~ **consider new or upgraded** transmission ~~and distribution~~ facilities ~~required to meet, in an economical and reliable manner, future electric service requirements~~ **as a resource in meeting future electric service requirements, including new**

projects, efficiency improvements, and smart grid resources. The ~~plan~~ **IRP** shall, at a minimum, include the following:

(1) ~~An analysis of transmission network capability to reliably support the loads and resources placed upon the network.~~

~~(2) A list of the principal criteria upon which the design of the transmission network is based. Include an explanation of the principal criteria and their significance in identifying the need for and selecting transmission facilities.~~

~~(3)~~ A description of the timing and types of expansion and alternative options considered.

~~(4)~~ **(2)** The approximate cost of expected expansion and alteration of the transmission network.

(3) A description of how the IRP accounts for the value of new or upgraded transmission facilities for the purposes of increasing needed power transfer capability and increasing the utilization of cost effective resources that are geographically constrained.

(4) A description of how:

(A) IRP data and information are used in the planning and implementation processes of the RTO of which the utility is a member; and

(B) RTO planning and implementation processes are used in and affect the IRP.

(Indiana Utility Regulatory Commission; 170 IAC 4-7-6; filed Aug 31, 1995, 9:00 a.m.: 19 IR 22; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA)

SECTION 10. 170 IAC 4-7-7 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-7 Selection of future resources

Authority: IC 8-1-1-3

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 7. (a) In order to eliminate nonviable alternatives, a utility shall perform an initial screening of all future resource alternatives listed in sections 6(b) through **6**(c) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported **in, but not limited to, a resource summary table. The following information must be provided for a resource selected for further analysis:**

(1) Significant environmental effects, including the following:

(A) Air emissions.

(B) Solid waste disposal.

(C) Hazardous waste and subsequent disposal.

(D) Water consumption and discharge.

(2) An analysis of how existing and proposed generation facilities conform to the utility-wide plan to comply with existing and reasonably expected future state and federal environmental regulations, including facility-specific and aggregate compliance options and associated performance and cost impacts.

(b) Integrated resource planning includes one (1) or more tests used to evaluate the cost-effectiveness of a demand-side resource option. A cost-benefit analysis must be performed using the following tests except as provided under subsection (e):

(1) Participant.
(2) Ratepayer impact measure (RIM).
(3) Utility cost (UC).
(4) Total resource cost (TRC).
(5) Other reasonable tests accepted by the commission.

(c) A utility is not required to express a test result in a specific format. However, a utility must, in all cases, calculate the net present value of the program impact over the life cycle of the impact. A utility shall also explain the rationale for choosing the discount rate used in the test.

(d) A utility is required to:
(1) specify the components of the benefit and the cost for each of the major tests; and
(2) identify the equation used to express the result.

(e) If a reasonable cost-effectiveness analysis for a demand-side management program cannot be performed using the tests in subsection (b), where it is difficult to establish an estimate of load impact, such as a generalized information program, the cost-effectiveness tests are not required.

(f) To determine cost-effectiveness, the RIM test must be applied to a load building program. A load building program shall not be considered as an alternative to other resource options.

(Indiana Utility Regulatory Commission; 170 IAC 4-7-7; filed Aug 31,1995, 9:00 a.m.: 19 IR 23; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA)

SECTION 11. 170 IAC 4-7-8 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-8 Resource integration
Authority: IC 8-1-1-3
Affected: IC 8-1-8.5; IC 8-1.5

Sec. 8. **(a) The utility shall develop candidate resource portfolios from the selection of future resources in section 7 and provide a description of its process for developing its candidate resource portfolios.**

(b) ~~A~~ **From its candidate resource portfolios, a** utility shall select a ~~mix of resources consistent with the objectives of the integrated resource plan. The utility must~~ **preferred resource portfolio and** provide ~~the commission~~, at a minimum, the following information:

(1) Describe the utility's ~~resource plan~~ **preferred resource portfolio**.

(2) Identify the variables, standards of reliability, and other assumptions expected to have the greatest effect on the ~~least-cost mix of resources~~ **preferred resource portfolio**.

(3) ~~Determine the present value revenue requirement of the utility's resource plan, stated in total dollars and in dollars per kilowatt-hour delivered, with the discount rate specified.~~ **Demonstrate that supply-side and demand-side resource alternatives have been evaluated on a consistent and comparable basis.**

(4) Demonstrate that the ~~utility's resource plan~~ **preferred resource portfolio** utilizes, to the extent practical, all economical load management, ~~conservation~~**demand side management**, ~~nonconventional~~ technology relying on renewable resources, cogeneration, **distributed generation, energy storage, transmission,** and energy efficiency improvements as sources of new supply.

(5) ~~Discuss how the utility's resource plan takes into account the utility's judgment of risks and uncertainties associated with potential environmental and other regulations.~~
~~(6) Demonstrate that the most economical source of supply-side resources has been included in the integrated resource plan.~~
~~(7)~~ Discuss the utility's evaluation of ~~dispersed generation and~~ targeted DSM programs including their impacts, if any, on the utility's transmission and distribution system for the first ten (10) years of the planning period.
~~(8)~~ **(6)** Discuss the financial impact on the utility of acquiring future resources identified in the utility's ~~resource plan~~ **preferred resource portfolio.** The discussion **of the preferred resource portfolio** shall include, where appropriate, the following:

(A) ~~The~~ Operating and capital costs~~of the integrated resource plan~~.

(B) The average ~~price~~**cost** per kilowatt-hour ~~as calculated in the resource plan. The price~~**, which** must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule.

(C) An estimate of the utility's avoided cost for each year of the ~~plan~~ **preferred resource portfolio**.

(D) ~~The impact of a planned addition to supply-side or demand-side resources on the utility's rate.~~

~~(E)~~ The utility's ability to finance the ~~acquisition of a required new resource~~**preferred resource portfolio**.

~~(9) Identify and explain assumptions concerning existing and proposed regulations, laws, practices, and policies made concerning decisions used in formulating the IRP.~~
(7) Demonstrate how the preferred resource portfolio balances cost minimization with cost-effective risk and uncertainty reduction, including the following.

(A) Identification and explanation of assumptions.

(B) Quantification, where possible, of assumed risks and uncertainties, which may include, but are not limited to:

(i) regulatory compliance;

(ii) public policy;

(iii) fuel prices;

(iv) construction costs;

(v) resource performance;

(vi) load requirements;

(vii) wholesale electricity and transmission prices;

(viii) RTO requirements; and

(ix) technological progress.

(C) An analysis of how candidate resource portfolios performed across a wide range of potential futures.

(D) The results of testing and rank ordering the candidate resource portfolios by the present value of revenue requirement and risk metric(s). The present value of revenue requirement shall be stated in total dollars and in dollars per kilowatt-hour delivered, with the discount rate specified.

(E) An assessment of how robustness factored into the selection of the preferred resource portfolio.

~~(10)~~ **(8)** Demonstrate, to the extent practicable and reasonable, that the ~~utility's resource plan~~ **preferred resource portfolio** incorporates a workable strategy for reacting to unexpected changes. A workable strategy is one that allows the utility to adapt to unexpected circumstances **quickly and appropriately** ~~and preserves the plan's ability to achieve its intended purpose~~. Unexpected changes include, but are not limited to, the following:

(A) The demand for electric service.

(B) The cost of a new supply-side or demand-side technology.

(C) **Regulatory compliance requirements and costs.**

(D) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.

(Indiana Utility Regulatory Commission; 170 IAC 4-7-8; filed Aug 31, 1995, 9:00 a.m.: 19 IR 23; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA)

SECTION 12. 170 IAC 4-7-9 IS AMENDED TO READ AS FOLLOWS:

170 IAC 4-7-9 Short term action plan

Authority: IC 8-1-1-3

Affected: IC 8-1-8.5; IC 8-1.5

Sec. 9. A short term action plan shall be prepared as part of the utility's IRP ~~filing or separately~~, and shall cover each of the ~~two (2)~~ **three (3)** years beginning with the IRP submitted pursuant to this rule. The short term action plan is a summary of the ~~resource options or programs contained in the utility's current integrated resource plan~~ **preferred resource portfolio and its workable strategy, as described in 170 IAC 4-7-8(b)(8),** where the utility must take action or incur expenses during the ~~two (2)~~ **three (3)** year period. The short term action plan must include, but is not limited to, the following:

(1) A description of each resource ~~option or program~~ **in the preferred resource portfolio** included in the short term action plan. **The description may include references to other sections of the IRP to avoid duplicate descriptions.** The description must include, but is not limited to, the following:

(A) The objective of the ~~resource option or program~~ **preferred resource portfolio**.

(B) The criteria for measuring progress toward the objective.

~~(C) The actual progress toward the objective to date.~~

(2) ~~The participation of small business in the implementation of a DSM resource option or program.~~

~~(3)~~ The implementation schedule for the ~~resource option or program~~ **preferred resource portfolio**.

~~(4) The timetable for implementation and resource acquisition.~~

~~(5)~~ **(3)** A ~~detailed~~ budget **with an estimated range** for the cost to be incurred for each resource or program **and expected system impacts**.

(4) A description and explanation of differences between what was stated in the utility's last filed short term action plan and what actually transpired.

(Indiana Utility Regulatory Commission; 170 IAC 4-7-9; filed Aug 31, 1995, 9:00 a.m.: 19 IR 24; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA)

SECTION 13. 170 IAC 4-7-10 IS ADDED TO READ AS FOLLOWS:

170 IAC 4-7-10 Updates
Authority: IC 8-1-1-3
Affected: IC 8-1-8.5; IC 8-1.5

Sec. 10. (a) The utility may provide an update regarding substantial unexpected changes that occur between IRP filings.

(b) Upon the request of the commission or its staff, the utility shall provide the requested updated IRP information.

(Indiana Utility Regulatory Commission; 170 IAC 4-7-10)

Exhibit 2

COMISIÓN DE ENERGÍA DE PUERTO RICO

DEPARTMENT OF STATE
No: 9021
Date: April 24, 2018
Approved . Hon. Luis G. Rivera Marín
Secretary of State

By Eduardo Arosemena Muñoz
Assistant Secretary

REGULATION ON INTEGRATED RESOURCE PLAN FOR THE PUERTO RICO ELECTRIC POWER AUTHORITY

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REGULATION ON INTEGRATED RESOURCE PLAN FOR THE PUERTO RICO ELECTRIC POWER AUTHORITY

CHAPTER I - GENERAL PROVISIONS

ARTICLE I.- GENERAL PROVISIONS

Section 1.01.- Title.

This Regulation shall be known as the Regulation on Integrated Resource Plan for the Puerto Rico Electric Power Authority.

Section 1.02.- Legal Basis.

This Regulation is adopted pursuant to Articles 6.3, 6.20 and 6.23 of Act 57-2014, as amended, known as the Puerto Rico Energy Transformation and RELIEF Act; to Section 6C of Act No. 83 of May 2, 1941, as amended, known as the Electric Power Authority Act ("Act 83"); and pursuant to Act 38-2017, as amended, known as the Uniform Administrative Procedure of the Government of Puerto Rico Act.

Section 1.03.- Purpose and Executive Summary.

The Puerto Rico Energy Commission ("Commission") adopts and enacts this Regulation in compliance with the mandate established in Section 6C of Act No. 83 of May 2, 1941, as amended, known as the Puerto Rico Electric Power Authority Act, and Section 6.23 of Act 57-2014, known as the Puerto Rico Energy Transformation and RELIEF Act, which require the adoption of the necessary rules for the elaboration, presentation, evaluation, and approval of the Puerto Rico Electric Power Authority's ("PREPA") Integrated Resource Plans (IRP).

Pursuant to this Regulation and resulting from a detailed planning process, the IRP will consider all the reasonable resources to satisfy the demand for electricity services during a twenty (20)-year planning period, taking into account both supply- and demand-side electric power resources. In broad terms, the IRP will include an assessment of the planning environment, a careful and detailed study of a range of future load forecasts, present generation resources, present demand resources, current investments in electricity conservation technologies, existing transmission and distribution facilities, and the relevant forecast and scenario analyses in support of PREPA's selected resource plan. It will also contain a discussion of all applicable laws and regulations to ensure that the proposed Action Plan for the implementation of the selected resource plan complies with all laws and regulations of the Federal government and the Commonwealth of Puerto Rico.

The purpose of this Regulation is to ensure that the IRP serves as an adequate and useful tool to guarantee the orderly and integrated development of Puerto Rico's electric power system, and to improve the system's reliability, resiliency, efficiency, and transparency, as well as the provision of electric power services at reasonable prices. The provisions established herein will guide the IRP process along lines that are consistent with the mandates of Act 57-2014 and Act No. 83 of May 2, 1941, and following the electric power industry's best practices in integrated resource planning. This Regulation, moreover, defines the terms related to the information required in the IRP, the procedures before the Commission, and the performance metrics guideline and inducements that PREPA will follow after the Commission has evaluated and reviewed the IRP. The Commission will evaluate the IRP as well as PREPA's performance thereafter in accordance with the provisions set forth in this Regulation.

Section 1.04.- Application.

This Regulation shall govern the information requirements, guidelines for analysis, action plans, performance measures, as well as the evaluation, approval, and review procedures related to the Integrated Resource Plans for the Puerto Rico Electric Power Authority.

Section 1.05.- Interpretation.

This Regulation shall be interpreted in a way that promotes the highest public good and the protection of the interests of the residents of Puerto Rico, and in such a way that the proceedings are carried out rapidly, justly and economically.

Section 1.06.- Provisions of Other Regulations; Repeal of Regulation No. 8594, as amended by Regulation No. 8903.

The provisions of this Regulation may be supplemented by the provisions of other regulations of the Commission that are compatible with the provisions of this Regulation.

Regulation No. 8594, known as the Regulation on Integrated Resource Plan for the Puerto Rico Electric Power Authority, as amended by Regulation No. 8903, known as the Amendment to Regulation No. 8594, is hereby repealed.

Section 1.07.- Unforeseen Proceedings.

When a specific proceeding has not been planned for in this or another Commission regulation, the Commission may conduct them in any way that is consistent with Act 57-2014, as amended.

Section 1.08.- Definitions.

A) These definitions are to be used for this Regulation and are not intended to modify the definitions used in any other Commission rules or orders.

B) For the purposes of this Regulation, the following terms will have the meaning established below, except when the context of the content of any provision clearly indicates something else:

   1) "Action Plan" refers to a plan that identifies the specific actions that

PREPA will perform during the first five (5) years of the Planning Period in order to implement the Preferred Resource Plan.

2) "Advanced meter" refers to a meter that records a customer's electricity usage for time intervals of one hour or less, and can transmit that information to the utility without the need for a human meter reader. The meter allows for the two-way flow of information and enables the utility to identify a power outage.

3) "Baseline Load Forecast" refers to a load forecast of electricity demand and consumption that takes into account currently implemented demand-side resources and the expiration of such resources, but does not include any anticipated or required future demand-side resources.

4) "Capacity Expansion Model" refers to a computer model designed to seek a least cost, or "optimal", portfolio of electricity supply- and demand-side resources that meets the utility's load forecast, accounting for system constraints and the need to maintain the reliability of the system over the planning period in the Preferred Resource Plan.

5) "Cogeneration" refers to the production of electricity using waste heat from an industrial process or the use of steam from electric power generation as a source of heat.

6) "Commission" refers to the Puerto Rico Energy Commission created by virtue of Act 57-2014.

7) "CEPPO" refers to the Commonwealth Energy Public Policy Office created by virtue of Act 57-2014.

8) "Competitive bidding" shall mean the process by which supply- or demand-side resources are procured through a formal bidding or request for proposal ("RFP") process. For purposes of this regulation, a "Competitive bidding" process shall refer to the procedures set forth in Sections 6B(a)(iii) and 6C of Act 83 and any applicable Commission regulation or resolution.

9) "Demand-Side Resource" refers to the resources produced by energy efficiency programs, demand response programs, and distributed generation that reduce retail customer consumption or shift the time of consumption from end users.

10) "Demand Response Program" shall mean a program that seeks to modify customer loads to make them more efficient by reducing or shifting load from hours with high electricity costs or reliability constraints. Demand Response programs may include, but are not

limited to, any one or a combination of: direct load control programs, critical peak pricing, time-varying rates, other rate designs to encourage efficient electricity consumption, and other utility-designed or customer-managed programs that may become available through deployment of advanced meters or other technologies.

11)"Distributed Generation" shall mean generation facilities owned by retail customers and located on the customer side of the meter, that is primarily for the use and consumption of energy by retail customers, and that may provide any electric power generated in excess to PREPA. Distributed generation resources may include combined heat and power, renewable and non-renewable generators, microgrids and storage technologies including electric vehicles. Distributed generation includes both customer-owned and -leased resources.

12)"Electric power grid" shall mean the electric power transmission and distribution infrastructure of the Commonwealth of Puerto Rico, operated, supported, and administered by PREPA.

13)"Electricity consumption" shall mean the amount of electricity required by customers over the course of a year or smaller time period, as measured in gigawatt hours (GWh).

14)"Electricity demand" shall mean the amount of electricity required by customers at a given hour of the year, as measured in megawatts (MW).

15)"Energy Efficiency Measure" shall mean an installed piece of equipment or system, or modification of equipment, systems, or operations on end-use customer facilities that reduces the total amount of electrical energy and capacity that would otherwise have been needed to deliver an equivalent or improved level of service to end-use customers.

16)"Energy Efficiency Program" shall mean a program provided by or on behalf of PREPA to retail customers, using a set of energy efficiency measures to reduce the total amount of electrical energy and capacity that would otherwise have been needed to deliver an equivalent or improved level of end-use service.

17)"Environmental Regulations" shall mean the rules and regulations promulgated by the United States Environmental Protection Agency ("EPA") or the Environmental Quality Board of Puerto Rico ("EQB") and any applicable Federal and Puerto Rico environmental statutes.

18)"ICPO" refers to the Independent Consumer Protection Office, created by virtue of Act 57-2014.

19)"Independent Power Producer" shall mean an independently-owned generation facility that provides wholesale power to PREPA through a contractual arrangement.

20)"Integrated Resource Plan" or "IRP" shall mean a plan that considers all reasonable resources to satisfy the demand for electric power services during a specific period of time, including those relating to the offering of electric power, whether existing, traditional, and/or new resources, and those relating to energy demand such as energy conservation and efficiency or demand response and localized energy generation by the customer, while recognizing the obligation of compliance with laws and regulations that constrain resource selection.

21)"Intervenor" refers to any party who has filed for and been granted intervention in this proceeding pursuant to Section 5.05 of Regulation No. 8543, Regulation on Adjudicative, Notice of Noncompliance, Rate Review and Investigation Procedures.

22)"Load Forecast" refers to a long-term forecast of electricity demand (measured in MW) and electricity consumption (measured in GWh).

23)"Major Change" shall mean any new procurement effort or addition, retirement or modification of generation plant having a nameplate capacity of 50 megawatts or greater; the addition of pollution control equipment; the unanticipated termination of a Power Purchase Agreement; or other event, such as a major hurricane, as set forth by the Commission.

24)"Major Project" shall mean any project greater than 50 megawatts.

25)"Microgrid" shall mean a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the distribution grid. A microgrid can connect and disconnect from the distribution grid, when available, to enable it to operate in either grid-connected or off the grid (islanded) mode.

26)"New Resource or Facility" refers to any resource or facility that is in planning, unbuilt, undelivered, under construction, or is otherwise incomplete and that is not providing useful customer service.

27)"Person" includes any natural person, company or legal entity, independent of how it is organized.

28)"Planning Environment" refers to the statutes, rules, regulations, and other exogenous considerations that impact or guide electric system planning.

29)"Planning Period" shall mean the twenty-year period in an Integrated Resource Plan for which resources must be planned to meet customer load requirements.

30)"Planning Reserve Margin" refers to the reserve margin required to operate PREPA's system reliably.

31)"Power Purchase" refers to a transaction to purchase wholesale capacity and/or energy from another electric power supplier as approved by the Commission.

32)"PREPA" refers to the Puerto Rico Electric Power Authority, a corporate entity created by virtue of Act 83.

33)"Preferred Resource Plan" shall mean a portfolio of resource additions selected by PREPA from amongst those evaluated in the IRP representing the best performing resource mix to be implemented in the Action Plan.

34)"Rate Design" shall mean the means by which class revenue requirements are collected within each customer class in order to recover costs for the delivery of service and to promote efficient use of electricity services, including considerations for effective conservation and management of peak loads.

35)"Reference Case" refers to the forecast of load and associated system requirements, commodity prices, capital costs and risks representing PREPA's best understanding of expected circumstances or median probability outcomes.

36)"Resource Plan" refers to a selection of supply-, demand-side, and transmission resources that best serves PREPA's needs under a given forecast scenario.

37)"Revenue Requirement" refers to the total revenues required by PREPA to recover its capital investments and expenses as determined in a rate case decision issued by the Commission.

38)"Scenario" refers to a combination of system requirements needed to serve load, commodity prices, capital costs and risks that influence the choice of resources serving PREPA's future load.

39)"Small Power Production" refers to the production of electric power using oil and/or its byproducts, natural gas, renewable energy sources, or any other electric power production method, including the production of electric power through distributed generators of 1 MW or higher participating in PREPA's Net Metering Program.

40)"Supply-Side Resource" shall mean an electric generation, transmission, or distribution facility on the utility side of the meter, either owned or operated by PREPA, or the output of which is purchased by PREPA at wholesale.

41)"Work Papers" shall mean all documents, spreadsheets, reports, correspondence and communications, computer runs, calculations, and other materials relied upon to develop the IRP filing, including the Preferred Resource Plan and the Action Plan.

C) Every word used in the singular in this Regulation, shall be understood to also include the plural, unless the context indicates otherwise.

Section 1.09.- Dates and Terms.

In computing any time-period established in this Regulation, or by order of the Commission, the day of the occurrence of the event, act, or omission that triggers the period shall not be counted and the fixed period shall begin on the day after. If a period ends on a Saturday, Sunday or legal holiday, the period shall be extended until the next workday.

Section 1.10.- Language.

A) If there is a discrepancy between the Spanish version and the English version of this Regulation, the provisions of the English version shall prevail.

B) The proceedings heard before the Commission shall be conducted in the English language. At its discretion, and upon request from a party or *motu propio*, the Commission may require any party to file Spanish a translation of any document filed, prepared and developed in relation to an IRP proceeding. Any party seeking a waiver from this requirement shall file a duly grounded request with the Commission. Upon filing of such request, the Commission will issue a resolution notifying its determination with regards to such request and adopting appropriate remedies.

C) Except as otherwise authorized by the Commission, all allegations, appeals and motions should be written in English.

D) All documents submitted in any language that is not Spanish or English shall be accompanied by a certified translation into English.

Section 1.11.- Severability.

If any article, provision, word, sentence, paragraph or section of this Regulation is challenged, for any reason, before a court and declared unconstitutional or void, such ruling shall not affect, damage, or invalidate the remaining provisions of this Regulation and its effect shall be limited to the article, provision, word, sentence, paragraph or section declared unconstitutional or void. The nullity or invalidity of any article, word, sentence, paragraph or section in a specific case, shall not affect or jeopardize in any way its application or validity in any other case, unless it is expressly and specifically invalidated for all cases.

Section 1.12.- Forms.

The Commission shall establish the forms it deems necessary to conduct the proceedings pursuant to this Regulation, and shall inform the public via its website. Notwithstanding, the fact that the Commission has not adopted one or more forms, is in the process of reviewing them, or the Internet website is out of service, shall not relieve anyone of its obligation to comply with the provisions stated herein or the Commission's orders.

Section 1.13.- Mode of Submission.

The forms, documents and appearances required by virtue of this Regulation or any order of the Commission, shall be filed with the Commission pursuant to the rules, regulations and instructions adopted and published by the Commission to such effect. Upon the initiation of an IRP proceeding, the Commission may adopt through resolution and order specific filing instructions applicable to such IRP proceeding.

Notwithstanding, any IRP filing made by PREPA prior to the adoption by the Commission of specific filing instructions shall comply with the following:

A) An original and one copy shall be physically filed and stamped at the Commission Clerk's Office.

B) Along with the paper filing, PREPA shall provide the complete filing in an electronic format specified by the Commission during Phase 1 (as defined in Section 3.01), which shall include a searchable PDF electronic copy of the entire filing. Work papers and similar documents shall be saved in their native programs with formulae and references intact. Under no circumstances shall PREPA file a scanned, non-searchable copy of its filing (the only exception being documents attached or made part of PREPA's filing which were not produced, developed or prepared in relation to the IRP filing and for which a searchable PDF version is not reasonably available).

Section 1.14.- Effect of Submission.

In filing a document in relation to any IRP proceeding, the party making such filing expressly certifies and recognizes that the content of said document is true and that, according to the signer's best knowledge, information and belief, formed after reasonable inquiry, the document is based on reliable facts, arguments, judicial sources and information.

Section 1.15.- Confidential Information.

If in compliance with the provisions of this Regulation or any of the Commission's orders, a person is required to file with the Commission information it considers to be privileged or confidential pursuant to applicable evidentiary privileges, said person shall identify the alleged privileged information and request the Commission to treat such information as confidential, pursuant to Article 6.15 of Act 57-2014. In identifying privileged information and requesting confidential treatment by the Commission, the requesting party shall follow the rules and procedures adopted from time to time by the Commission for the filing, handling and treatment of confidential information in resolution CEPR-MI 2016-0009 as currently amended and as may be amended from time to time. Except in the case of information protected under the attorney-client privilege, the claiming of confidential treatment shall, under no circumstances, be grounds for denying such information from being filed with the Commission.

Section 1.16.- Validity.

Pursuant to Section 2.8 of Act 38-2017, this Regulation shall enter into effect thirty (30) days after its submission to the Department of State and the Legislative Library of the Office of Legislative Services.

CHAPTER II – INTEGRATED RESOURCE PLANNING

ARTICLE II.- PLANNING PERIOD, CONTENT AND SCHEDULE

Section 2.01.- Planning Period; Effectiveness.

A) The IRP shall consider a planning period of twenty (20) years.

B) An IRP approved by the Commission shall remain in effect until the approval of a subsequent IRP by the Commission, or until otherwise established by the Commission through resolution or order.

C) Any proposal for a new IRP, or any proposed update, review or amendment to an existing IRP must be submitted to the Commission for evaluation and approval. An update, revision or amendment to an IRP, in whole or in part, will not enter into effect until it is approved by the Commission.

Section 2.02.- Integrated Resource Plan Filing Structure and Requirements

A) The IRP filing shall be comprised of a main body and accompanying technical appendices, as established in paragraphs (B) and (C), below.

B) The main body of the IRP filing shall be organized into the following chapters:

Part One - Introduction and Summary of Conclusions

Part Two - Planning Environment

Part Three - Load Forecast

Part Four - Existing Resources

Part Five - Resource Needs Assessment

Part Six - New Resource Options

Part Seven - Assumptions and Forecasts

Part Eight - Resource Plan Development

Part Nine - Caveats and Limitations

Part Ten - Action Plan

C) The main body of the IRP filing shall be written as a coherent, stand-alone document designed to allow informed readers sufficient information to understand the process by which PREPA conducts long-term resource planning, and the key outcomes of that resource planning.

D) The technical appendices of the IRP filing shall include all ancillary information and descriptions required by this Regulation but not included in the main body of the IRP filing. The following technical appendices must be attached to the IRP filing:

Appendix 1 - Transmission and Distribution Planning

Appendix 2 - Prior Action Plan Implementation Status

Appendix 3 - Renewable Energy Project Status

Appendix 4 - Demand-Side Resources

Appendix 5 - New and Existing Supply-Side Resources Supplemental Data

Appendix 6 - Additional information, as required by the Commission through an Order, that may address additional subjects related to integrated resource planning.

E) The IRP filing shall specifically identify and include all references to external or internal (PREPA) source documents relied upon for the development of the proposed IRP.

1) If a source document is publicly available on the Internet, a specific link (URL address) to the source document shall be provided.

2) If a source document referenced by PREPA in any portion of its IRP filing is not publicly available or readily accessible, an electronic copy of such source documents shall be provided along with the IRP filing.

3) If a source document consists of a study, report, book, periodical, or other publication not publicly available or readily accessible, PREPA shall provide copies of the relevant pages from such source document relied upon by PREPA in the development of its proposed IRP. All pages which are necessary to understand the relevant pages in context shall be provided. Upon request, PREPA shall make available the entirety of such source document. In the case such source documents are protected under federal copyright law, PREPA shall make a reference to the documents used for the development of the proposed IRP.

F) Work Papers and models relied upon by PREPA in the development of the IRP shall be filed concurrently with the IRP.

1) Work Papers which are available in electronic form shall be provided electronically in native format. All formulae and viable links shall be left intact for all electronic files. PREPA shall, at a minimum, provide the following workpapers to the Commission upon submission of the IRP:

a) Load Forecast Development workpapers;

b) Fuel Price Forecast Development workpapers;

c) Resource Plan modeling input files;

d) Resource Plan modeling output files as used by PREPA;

e) Any post-processing or analysis work papers used to assess the Resource Plan modeling output files, including financial models used to calculate the present value of revenue requirements, rate impacts or other cost elements of the IRP;

f) Electronic, spreadsheet-based versions of all tables and figures as presented in the IRP.

2) PREPA shall provide to the Commission any computer model including the software and licensure necessary for the Commission, or its consultants, to independently run any analysis relied upon by PREPA. Alternatively, PREPA may provide the Commission reasonable access to the computer model at the Commission's offices or at another mutually agreeable location. Such access shall be adequate to enable the Commission to replicate the results and may include PREPA manipulating the computer model according to instructions or inputs from the Commission. Reasonable access shall be made available to intervenors. If PREPA seeks to limit access to the program or application to intervenors, the Commission will determine the appropriate access to the program or its output.

Section 2.03.- Integrated Resource Plan Analyses and Reporting Requirements

A) The IRP shall assess and report upon each of the following factors, as described in paragraphs (B) through (N) of this Section.

B) Planning Environment- PREPA shall present a description of significant planning and regulatory factors that affect the environment in which it operates as well as the way in which these factors impact PREPA's system.

   1) PREPA shall describe, at a minimum, the following factors: federal, state, or municipal standards and rules that impact the requirement for, or availability of, energy efficiency, renewable energy, fuel alternatives, or other resource requirements; and environmental standards and regulations that impact existing utility resources or resource choices at the present time and throughout the planning period.

   2) The Planning Environment section shall also include a discussion of substantial regulatory or legislative standards and rules that have changed since the approval of the most recent IRP.

C) Load Forecast- PREPA shall present a forecast of future capacity and energy demand requirements, as well as an analysis of prior load forecasts.

   1) Load Forecast Documentation- The IRP shall document the following elements of the load forecast.

      a) Forecast Peak Demand and Energy- Forecast data shall be reported, on a year by year basis, covering the entire IRP Planning Period, and shall include:

         i. The total annual electricity generation and sales for the utility and consumption for each customer class, determined in accordance with tariffs for billing.

         ii. The coincident peak electricity demand for the utility and each customer class.

      b) Forecasts shall be provided for the reference case as well as, at a minimum, the low and high baseline forecasts, as described in Section 2.03 (C)(2)(a)(ii) and (iii) below.

      c) Historic Peak Demand and Energy- Historic data shall be reported covering the ten-year (10-year) period prior to the first year of the IRP Planning Period, and shall include:

         i. The total annual electricity generation and sales for the utility and consumption for each customer class determined in accordance with tariffs for billing.

ii. The coincident peak electricity demand for the utility and each customer class.

d) Load Forecast Methodology Description- PREPA shall provide a detailed explanation of the method used to forecast load requirements throughout the Planning Period, the significant determinant variables that were incorporated in the Load Forecast methodology, and the method used by PREPA to select the reference, high and low load forecasts.

e) Prior Load Forecast Evaluation- PREPA shall prepare an evaluation of the load forecast provided in the most recent IRP, which shall include:

i. An assessment of the annual accuracy of the previous forecasting including a comparison of forecasted versus actual data;

ii. An explanation of the cause of any significant deviation between the previous forecasts and the actual annual peak demand and energy that occurred. For purposes of this sub-section, significant deviation refers to a difference of more than 5%.

iii. An explanation of the impact that historical demand-side resources had on the prior load forecast.

2) Load Forecast Analysis - PREPA shall develop peak electricity demand and annual electricity consumption forecasts for each year of the IRP Planning Period, according to the following criteria:

a) PREPA shall prepare at least three (3) baseline Load Forecasts to reflect a reasonable range of future uncertainties:

i. A reference case representing PREPA's best understanding of expected circumstances or median probability outcomes;

ii. A low case where customer electricity demand and consumption are significantly below utility median expectations through the Planning Period; and

iii. A high case where customer electricity demand and consumption are significantly above utility median expectations through the Planning Period.

b) The Load Forecasts shall be developed using methods that examine the effect of economic factors on electricity consumption, as well as the effect of the use of lands under the Land Use Plan for Puerto Rico.

c) A reasonable set of assumptions for econometric and/or end use variables shall be included in the development of the long-term Load Forecasts.

d) The Load Forecasts shall take into account all anticipated naturally occurring energy efficiency, as well as any energy efficiency resulting from existing and expected building codes and appliance standards.

e) Utility-sponsored or third-party energy efficiency and/or demand-response programs should be considered incremental system resources and thus excluded from the baseline Load Forecasts.

f) The Load Forecasts shall reflect normal weather conditions.

g) PREPA shall analyze and consider the impact that existing demand-side resources, anticipated changes to rate design, building codes and standards, deployment of distributed generation, and other important factors are expected to have on the Load Forecast.

h) PREPA shall analyze and consider the impact of technical losses in the Load Forecast, including the extent to which the forecast includes the effects of current and planned technical loss reduction programs.

i) PREPA shall analyze and consider the impact of non-technical losses in the Load Forecast, including the extent to which the forecast includes the effects of current and planned non-technical loss reduction programs.

D) Existing Resources- PREPA shall describe all existing resources that serve or meet PREPA's customer's energy and capacity requirements. The IRP shall include the following:

1) Existing Supply-Side Resource Documentation- PREPA shall describe the energy supply from existing supply-side resources, providing information about the fleet of generators that serve PREPA customers.

a) PREPA shall describe each type of supply-side resources, including at least the following categories:

i. Utility-owned generation;

ii. Wholesale power purchase transactions that are one (1) year or longer in duration and a detailed discussion of the same, including the term of the contract, expiration date, pricing provisions, source of the power, fuel source, and other relevant information;

iii. Cogeneration and Small Power Production;

iv. Distributed Generation;

v. Pooling or coordination agreements that reduce resource requirements; and

vi. Any other supply-side resources.

b) Existing Supply-Side Resource Table- The following information concerning each existing supply-side resource shall be supplied, as applicable and as readily available to PREPA with respect to private resources, in the form of a coherent table(s) in the body of the IRP:

i. Resource type;

ii. Nameplate and peak available capacity;

iii. Annual capacity factor for each of the last five (5) years;

iv. Fuel type;

v. Ownership information, including the portion of the resource owned by PREPA, by a private project developer, or by a customer;

vi. Location (district or municipality);

vii. Commercial operation date;

viii. Remaining service life;

ix. Any anticipated projects or programs that would alter remaining service life;

x. Remaining contract life;

xi. Average annual heat rate over the last five (5) years;

xii. Current fuel cost in dollars per MMBtu;

xiii. Current variable operations and maintenance (O&M) cost in dollars per MWh;

xiv. Current total production cost in dollars per MWh, including any other necessary variables aside from fuel and variable O&M costs;

xv. Current fixed O&M cost in dollars per kW;

xvi. Average annual capital expenditures over the last five (5) years in total dollars;

c) Existing Supply-Side Resource Supplemental Data- The following information concerning each existing supply-side resource shall be supplied as part of Appendix 5 identified in Section 2.02(D) of this Regulation.

i. All information in sub-section (b) above;

ii. Expected retirement date for any resource expected to retire within the first ten (10) years of the Planning Period, and an explanation of the reason for the retirement;

iii. Dates for renewal of operating licenses and permits, to the extent applicable; and

iv. Compliance schedule with current, proposed, and reasonably anticipated regulatory (including environmental regulatory) and legal requirements, to the extent applicable;

v. Expected capital and operating costs for compliance with current, proposed, and reasonably anticipated regulatory (including environmental regulatory) and legal requirements, to the extent applicable;

vi. Expected yearly non-environmental capital expenditures for the first ten (10) years of the Planning Period, including any improvements to operational efficiencies or extensions of the useful life;

vii. Any important changes to the resources that occurred since the approval of the most recent IRP or which is expected to occur prior to the filing of a review, update or amendment IRP, including:

A. A description of each large capital project (over $5,000,000) expected in the next (5) years;

B. Changes in fuel types, or procurement sources or strategies; and

C. Operational changes expected to result from economic restrictions or environmental regulations.

viii. A description, with quantitative information and analysis as required, of how the resource contributes to meeting the requirement for "high efficiency" generation, as that term is defined by the Commission, in accordance with Section 6.29(a) of Act 57.

2) Existing Demand-Side Resource Documentation- The IRP shall describe all demand-side resources currently being implemented by or on behalf of PREPA. The resource descriptions shall be consistent with the most recent Energy Efficiency and Demand Response Annual Report and Energy Efficiency and Demand Response Plan ("Annual Report and Plan"), as described in Section 4.01 of this Regulation. Any inconsistencies or changes with respect to existing demand-side resources relative to what is described in the most recent Annual Report and Plan shall be described in detail.

E) Resource Needs Assessment– PREPA shall prepare a Resource Needs Assessment and describe in detail the results of such assessment. The purpose of the Resource Needs Assessment is to identify current and/or future expected capacity and/or energy requirements resulting from the expected or contractual retirement of, or cessation of services from, existing supply and demand-side resources when compared against forecast load conditions. The Resource Needs Assessment shall contain at least the following elements:

1) Planning Reserve Margin Assessment- PREPA shall assess and describe in detail its expected Planning Reserve Margin over the Planning Period.

a) The Planning Reserve Margin Assessment shall follow industry standard methodologies in assessing a necessary planning reserve margin to maintain reliable service during the Planning Period.

b) To the extent that the Reserve Margin Assessment cannot be developed independently of a resource plan, PREPA may use its then-current business plan to assess and describe the necessary planning reserve margin.

c) PREPA shall demonstrate why the Planning Reserve Margin targets in its forecast are reasonable.

2) Load and Resource Balance- PREPA shall prepare a coherent table showing, by year, the expected capacity of each existing supply-side and existing demand-side resource, its load requirements, and load requirements including the Planning Reserve Margin. PREPA shall identify its annual net position relative to its expected needs during the Planning Period.

F) New Resource Options- PREPA shall describe new resource options that may reasonably serve or meet PREPA's customer's energy and/or capacity requirements.

1) New Supply-Side Resource Option Identification– The IRP shall identify and evaluate a wide range of new supply-side resource options, including renewable and non-renewable options, to be used in the development of the IRP. While PREPA may designate specific options as not feasible for future development, such designations must be accompanied by a clear and comprehensive explanation that justifies PREPA's determination on the basis of cost, resource availability, or engineering feasibility.

a) New Supply-Side Resource Options Table- For each supply-side resource option identified as a feasible alternative, PREPA shall provide the following information, as applicable, in the form of a coherent table in the body of the IRP:

i. Resource type;

ii. Location, if a specific project site has been identified; otherwise, restrictions and other considerations that may dictate resource placement;

iii. Capacity;

iv. Fuel type;

v. Capacity factor for renewable energy resources;

vi. Effective load carrying capacity (ELCC) or capacity contribution to peak;

vii. Ownership information including the portion of the resource owned by PREPA, by a private project developer, or by a customer;

viii. Anticipated service life;

ix. Heat rate;

x. Overnight capital cost;

xi. Fixed O&M cost;

xii. Variable O&M cost;

b) New Supply-Side Resource Options Supplemental Data- For each of the resources identified in (a) above, the following information shall be supplied as part of Appendix 5 identified in Section 2.02(D) of this Regulation.

i. All information in (a), above, and

ii. Other costs to construct and/or operate the resource, including financing costs, property taxes, supplemental payments, and interconnection costs;

iii. Lead time necessary to plan and build, or acquire through a power purchase agreement;

iv. Any constraints on the acquisition or construction of the resource as applied by PREPA in the Capacity Expansion Model, including first potential date of construction, maximum units feasible to acquire or construct per year, and total number of the resources allowed in the model through the Planning Period;

v. Any constraints on the operation or the dispatch of the resource as applied by PREPA in its modeling, including minimum up-time, minimum down-time, or energy or effluent limitations;

vi. Any impact of the location of the resource on reliability and system resilience;

vii. Evaluation of the interconnection of renewable energy projects and other independent power producers to the utility system in order to comply with Act 82-2010, as amended.

viii. A description, with quantitative information and analysis as required, of how the resource contributes to meeting the requirement for "high efficiency" generation, as that term is defined by the Commission, in accordance with Section 6.29(a) of Act 57.

2) New Distributed Generation Resource Identification- The IRP shall include a projection and account for expected types and amounts of customer-owned distributed generation, by customer class.

   a) PREPA shall provide an analysis that forms the basis of its projections.

   b) PREPA shall include its projections of distributed generation in the IRP as an expected reduction from the baseline Load Forecasts.

3) New Demand-Side Options Identification- The IRP shall identify and include a wide range of potential new energy efficiency and demand response programs.

   a) PREPA shall identify, and include in its analysis, all demand-side programs currently being offered by or on behalf of PREPA.

   b) PREPA shall provide a description of the energy efficiency programs developed and implemented in conjunction with the Government of Puerto Rico to comply with Chapter IV of Act 57-2014, and detail the impact of such programs on PREPA's Resource Plan.

   c) The IRP shall consider all available cost-effective energy efficiency and demand response measures and programs.

   d) The IRP shall consider bundles of demand-side resources at varying levels of cost and effectiveness and their implementation throughout the Planning Period. The IRP shall list constraints on the acquisition of those resources, such as ramp rate, expected lifetime or decay, and year availability.

   e) Until such time as the Commission has approved the results of an energy efficiency and demand response potential study, or if said study shows that the maximum achievable cost-effective potential is greater than or equal to two percent (2%) on energy savings per year for at least ten years, the IRP shall consider the estimated cost of developing and implementing sufficient demand-side resources such that a target incremental saving of at least two percent (2%) per year, for at least 10 years, is achieved.

f) If the approved potential study shows that the maximum achievable cost-effective potential is less than two percent (2%) per year, the IRP shall consider the estimated cost of developing and implementing sufficient demand-side resources such that the maximum achievable cost-effective potential is achieved.

4) New Storage Resource Identification- The IRP shall identify and evaluate electrical energy storage options, including batteries.

a) For each electrical energy storage option considered, the IRP shall describe the anticipated use of the storage option, whether to reduce renewable curtailment, provide voltage and frequency stability and/or regulation, or other purposes.

b) The IRP shall include a valuation framework for energy storage options. Such valuation framework will contemplate at least the following:

i. Value provided by provision of ancillary services (which may include, but are not limited to, avoidance of load shedding);

ii. Value provided by load-shaping services (which may include, but are not limited to, load shifting or peak shaving); and

iii. Value provided by locational benefits (which may include, but are not limited to, congestion relief or deferral of T&D upgrades or expansions).

G) Assumptions and Forecasts

1) Model Assumption Documentation- The IRP shall document key modeling assumptions and inputs, including, at least, the following:

a) Annual fuel prices for each delivered fuel at Puerto Rico;

b) Annual emission prices;

c) Economic conditions;

d) Environmental regulations;

e) Other non-environmental regulations, including renewable portfolio standards;

f) Utility discount rate or weighted average cost of capital;

g) Annual debt limitations;

2) Model Assumption Development- The IRP shall identify factors that will significantly influence key forecasts (including electricity demand, electricity consumption, fuel prices), and develop a range of possible outcomes for those forecasts encompassing at least the fifth (5th) and ninety-fifth (95th) percentile outcomes as understood by PREPA.

a) Forecasts should include exogenous elements beyond PREPA's control, including but not limited to:

i. Economic conditions;

ii. Environmental regulations;

iii. Changes in customer load not caused by utility Demand-Side Resources;

iv. Customer-sited distributed generation;

v. Fuel prices;

vi. Emissions costs; and,

vii. Capital costs.

b) For each forecast, the IRP shall identify a reference case forecast, and describe the basis of the forecast range identified.

c) Scenario Development- The IRP shall consider multiple scenarios that encompass the reasonable range of possible outcomes for uncertain forecasts. Scenarios may combine key forecasts in a manner that enables a reasonable exploration of the range of foreseeable risks to the safety, reliability, and affordability of retail services. The IRP shall consider a sufficient number of scenarios to both describe feasible or likely sets of forecasts, as well as capture a wide range of possible risks.

i. PREPA shall justify the scenarios used and excluded from consideration, and describe why the combinations assessed represent a reasonable range of risks.

ii. To the extent that PREPA relies on explicit or implicit relationships or correlations between forecasts, PREPA shall describe the basis of the relationships.

iii. PREPA shall incorporate any scenarios required by the Commission as identified in Section 3.01(A) of this

Regulation.

d) Reference Case Scenario- The IRP shall include a Reference Case Scenario, representing PREPA's best understanding of expected circumstances or median probability outcomes.

H) Resource Plan Development

1) Resource Plan Development Documentation- The IRP shall identify in detail the mechanisms used by PREPA in developing its Resource Plans.

a) The IRP shall include, within the main body of the IRP, the following:

i. Comprehensive descriptions of the modeling mechanisms used in the development and sensitivity analysis of each Resource Plan, based on Capacity Expansion Models. PREPA may in addition use production costs models, a heuristic approach, or a combination of the two. The description should identify key steps to incorporate inputs and assumptions from sub-sections (C) through (G), above.

ii. Descriptions of key Resource Plan assumptions and purposes, including consideration of stakeholder input and Commission requirements.

iii. A coherent table illustrating the key differences between Resource Plans, including annual retirements, retrofits or conversions, and new builds for both supply and demand-side resources, changes in capacity (uprates or derations) of existing supply and demand-side resources, changes in transmission or distribution systems, key assumptions, and Resource Plan cost.

iv. A description of the mechanism and criteria used to select the Preferred Resource Plan, following the requirements in Section 2.03(H)(2)(d) below.

v. A coherent Load and Resource Balance table for the Preferred Resource Plan showing, by year, the expected capacity of each existing and new supply-side and demand-side resource, its expected peak load, its Planning Reserve Margin, and its total load requirements including the Planning Reserve Margin. PREPA shall identify its annual net position relative to its expected needs during the Planning Period.

b) For the Preferred Resource Plan, and for each Resource Plan considered in the IRP, the IRP shall include, at a minimum, the following supplemental information:

i. A table of annual capacity contribution by resource;

ii. A table of annual generation by resource;

iii. A table of annual emissions by resource;

iv. A table of annual fuel consumption by fuel type;

v. A cash-flow table comprised of annual cost values for, at a minimum, fuel spending by type of fuel, generation capital, transmission capital, fuel infrastructure capital, total generating unit variable O&M, total generating unit fixed O&M; fuel infrastructure O&M; CO_2, NO_x, and SO_2 emissions; fossil power purchase agreements; and renewable power purchase agreements.

2) Resource Plan Development Analysis-

a) Resource Plan Development Modeling- The IRP shall use a Capacity Expansion Model to develop least-cost Resource Plans that meet customer needs under the reference case scenario and various future scenarios. If PREPA does not use a Capacity Expansion Model to develop least-cost Resource Plans, the utility must seek, and receive, a waiver from the Commission to use any other kind of Resource Plan Development model for this purpose, in which case the Commission may adopt through resolution any and all appropriate requirements to ensure reliability of the information and conclusions produced and presented by PREPA.

i. The Capacity Expansion Model shall at a minimum:

A. Seek to optimize the present value of revenue requirements over the Planning Period;

B. Consider demand-side resources in a competitive framework with supply-side resources;

C. Recognize all utility-borne costs associated with the development of new resources;

D. Recognize all utility-borne costs, as well as avoided costs, associated with the retirement or modification of existing resources.

ii. Costs that PREPA has incurred or committed prior to the commencement of the Planning Period (including, but not limited to, existing plant balances, committed capital expenditures, and rate-based costs) shall not be assessed in the Capacity Expansion Model unless they are specifically avoidable through the procurement of new assets or retirement or modification of existing assets.

iii. PREPA shall use the Capacity Expansion Model to develop a comprehensive set of Resource Plans to include a wide variety of supply-side, energy efficiency, and demand response resources.

iv. Supply-side resources shall include various options for early retirement of existing power plants, for refurbishment or repowering of existing power plants, and for deferral of new power plants where feasible.

v. Supply-side resources shall also include any changes in the transmission or distribution systems that accompany generation resources or are necessary for the maintenance of system reliability.

vi. Energy efficiency and demand response resources shall include programs with a variety of different cost levels, in order to assist in the identification of all cost-effective energy and demand response resources.

vii. PREPA shall incorporate any Resource Plans required by the Commission as identified in Section 3.01(A).

viii. PREPA shall provide a comprehensive discussion of any Resource Plans excluded from consideration on the basis of reliability or viability.

ix. Each Resource Plan shall be designed to ensure that PREPA complies with the renewable portfolio standard requirements of Act 82-2010.

b) Resource Plan Sensitivity Analyses- Each of the Resource Plans resulting from the Resource Plan Development Modeling shall be subjected to sensitivity analyses exploring a reasonable range of uncertainty in forecast assumptions. The purpose is to examine the robustness of resource plans created in the optimization analysis (i.e., how each resource plan would be affected by changes in input assumptions).

i. The sensitivity analyses shall hold the resources developed in each Resource Plan constant and examine the impacts of changing uncertain forecasts.

ii. PREPA shall consider the following factors in the uncertainty analysis:

A. forward-looking economic conditions;

B. environmental regulations;

C. changes in customer electricity demand and consumption;

D. customer generation;

E. fuel prices;

F. environmental costs or restrictions;

G. construction costs; and,

H. combinations thereof as reasonable.

iii. PREPA may choose to use either the developed Planning Scenarios as sensitivities, develop a broader range of sensitivities, including single-factor sensitivities and multiple factor sensitivities, or use a Monte Carlo analysis framework, wherein uncertain forecasts are chosen and combined stochastically. The IRP shall describe and justify the basis of the sensitivity analysis made.

iv. The IRP shall present the outcome of each sensitivity analysis in present value of revenue requirements. If PREPA utilizes a Monte Carlo analysis, results should be presented as the median outcome and the fifth (5th) and ninety-fifth (95th) percentile costs.

v. These sensitivity analyses should be used to inform the selection of the Preferred Resource Plan.

c) Hybridized Alternative Resource Plans- PREPA may choose to modify one or more of the optimized Resource Plans based on the outcomes of the sensitivity analysis, if such a modification results in a Resource Plan that is of a comparable cost and demonstrably robust in the sensitivity analysis.

i. PREPA shall justify the modifications it has made to the Resource Plans used in the Hybridized Alternative Resource Plan.

ii. The use or analysis of this Hybridized Alternative Resource Plan does not preclude the complete analysis of other Resource Plans in the sensitivity analysis.

d) Preferred Resource Plan- PREPA shall select a Preferred Resource Plan from among the Resource Plans developed and evaluated in the optimization and sensitivity analyses.

i. In selecting the Preferred Resource Plan, PREPA shall use the minimization of the present value of revenue requirements as the primary selection criterion.

ii. PREPA shall also consider other criteria including, but not limited to, system reliability; short and long-term risk; environmental impacts; transmission needs and implications; distribution needs and implications; financial impacts on PREPA; and the public interest as set forth in Act 57-2014. Where meeting these needs is associated with quantifiable costs, these costs shall be included in the calculation of the present value of revenue requirements.

iii. The IRP shall include a detailed discussion of each of the above factors in support of its Preferred Resource Plan. PREPA may opt to choose a plan that is not the lowest cost, provided that, in doing so, it presents a detailed description of all the criteria and reasoning used to select the Preferred Resource Plan that is not the lowest cost.

I) Caveats and Limitations- The IRP shall include an annotated list of key caveats and limitations of its analysis, including the impact of uncertainty, the modeling mechanism, key regulatory and project execution assumptions, and costs. The purpose of this section is to illustrate PREPA's certainty with respect to the Preferred Resource Plan.

J) Transmission and Distribution Planning

1) Transmission and Distribution System Documentation

a) Existing Transmission Facilities Descriptions- The IRP shall include a brief narrative description of the existing electric transmission system and identify any transmission constraints and critical contingencies. The information shall include at a minimum:

   i. A summary of the characteristics of all existing transmission and subtransmission facilities of thirty-eight kilovolts (38 kV) or higher;

   ii. A discussion of whether the transmission system constrains the transfer of electricity from existing projects, potential new projects, or projects under development or consideration, including a description of its ability to interconnect intermittent renewable generation projects and microgrids, as applicable, and with as much specificity as practical;

   iii. A schematic map of the transmission and subtransmission network showing transfer limits, which shall be treated as Critical Energy Infrastructure Information and handled in accordance with the procedures set forth in CEPR-MI-2016-0009 as currently amended and may be amended from time to time; and

   iv. A map showing the actual, physical routing of the transmission and subtransmission lines, geographic landmarks, major metropolitan areas, and the location of substations and generating plants, and interconnections with distribution substations. The IRP shall include two copies of this map on a 1:250,000 scale. Such map shall be treated as Critical Energy Infrastructure Information and handled in accordance with the procedures set forth in CEPR-MI-2016-0009 as currently amended and may be amended from time to time.

b) Existing Distribution Facilities Description- The IRP shall include a brief narrative description of the distribution system, including description of its ability to accommodate incremental penetration of distributed generation, including intermittent distributed generation, and its ability to receive new loads over time, such as, for example, increasing penetrations of electric vehicles. In addition, the IRP shall provide PREPA's current distribution system design criteria. Information of PREPA's current distribution system shall include:

i. Load flow or other system analysis by voltage class of the electric utility's distribution system performance that identifies and considers each of the following:

A. Any thermal overloading of distribution circuits and equipment.

B. Any voltage variations on distribution circuits that do not comply with the current version of the American National Standard Institute ("ANSI") Standard C 84.1, Electric Power Systems and Equipment Voltage Ratings or Standard as later amended.

C. PREPA shall identify any portion of this analysis that it deems Confidential Energy Infrastructure Information. The Commission will handle it in accordance with the procedures set forth in CEPR-MI-2016-0009 as currently amended and may be amended from time to time.

ii. Adequacy of the electric utility distribution system to withstand natural disasters and overload conditions.

c) Existing Advanced Grid Technologies Description- The IRP shall identify the areas within the service territory where advanced meters and other advanced grid technologies have been installed, along with any plans to expand the integration of any such technologies into its system. The IRP shall include a brief description of the installed advanced grid technologies.

d) Planned Transmission Facilities Description- The IRP shall provide a detailed narrative description of any planned electric transmission and subtransmission facilities, and a description of the plans for development of facilities during the next ten years of the Planning Period. The description shall include, at a minimum, all information regarding:

i. New lines, including any requirements of new rights-of-way;

ii. Lines in which changes in capacity, either in terms of current, voltage or both, are scheduled to take place; and

iii. Other changes in transmission lines or rights-of-way, which would be considered as substantial additions.

iv. A listing of all proposed substations including size and location.

v. The transmission forecast shall include maps of the planned transmission system as follows:

   A. A map showing the planned transmission lines, substation, and generating plants as they will tie into the existing system to provide as complete a picture of the system as is possible.

vi. PREPA shall submit a justification of its of transmission development plans, including:

   A. Description and transcription diagrams of the base case load flow studies, one for the current year and one as projected five and ten years into the future, and provide base case load flow studies in a standard industry format (such as PSS/E or PSLF) along with transcription diagrams for the base cases. Such information shall be treated as Critical Energy Infrastructure Information and handled in accordance with the procedures set forth in CEPR-MI-2016-0009 as currently amended and may be amended from time to time.

vii. A tabulation of and transcription diagrams for a representative number of contingency cases studied along with brief statements concerning the results.

viii. Adequacy of PREPA's transmission system to withstand natural disasters and overload conditions.

ix. A high-level analysis of PREPA's transmission system's ability to permit power interchange with microgrids and other independent power producers. PREPA should provide examples of interconnection studies from recent renewable integration projects.

x. A diagram showing PREPA's import and export transfer capabilities and identifying the limiting element(s) during each season of the next ten years. In addition, PREPA will provide a listing of transmission loading relief (TLR) procedures called during the last two seasons for which actual data are available. For each TLR event, the listing shall include the maximum level, and the duration at the maximum level, and the magnitude (in MW) of the power curtailments.

xi. A description of any studies regarding transmission system improvement, including, but not limited to, any studies of the potential for reducing line losses, thermal loading, and low voltage, and for improving access to alternative energy resources.

xii. A one-line diagram of the transmission network. Such information shall be treated as Critical Energy Infrastructure Information and handled in accordance with the procedures set forth in CEPR-MI-2016-0009 as currently amended and may be amended from time to time.

e) Planned Distribution Facilities Description- The IRP shall provide a detailed narrative description of any planned changes in approach, standard practice, or broadly applicable substation, circuit, or feeder design for PREPA's distribution system for the next ten years. This description shall address any changes in distribution facilities that impact the ability to accommodate incremental penetration of distributed generation, including intermittent distributed generation, and the ability to receive new loads over time. PREPA shall submit a substantiation of distribution development plans, including, if available:

i. Load flow or other system analysis by voltage class of the electric utility's distribution system performance that identifies and considers each of the following:

A. Any thermal overloading of distribution circuits and equipment.

B. Any voltage variations on distribution circuits that do not comply with the current version of the American National Standard Institute ("ANSI") Standard C 84.1, Electric Power Systems and Equipment Voltage Ratings or Standard as later amended.

ii. Adequacy of the electric utility distribution system to withstand natural disasters and overload conditions.

iii. Analysis and consideration of any studies regarding distribution system improvement, including, but not limited to, any studies of the potential for reducing line losses, thermal loading and low voltage or any other problems, and for improving access to alternative resources.

2) Transmission and Distribution System Analysis

a) The IRP shall identify PREPA's transmission standards and shall confirm that the PREPA transmission standards are in compliance with the standards of the North American Electric Reliability Corporation. If any of PREPA's transmission standards are inconsistent with standards from the North American Electric Reliability Corporation, then PREPA shall identify each such inconsistent standard and provide the explanation and rationale for the inconsistency.

b) The IRP shall include a System Stability Analysis, which shall be treated as Critical Energy Infrastructure Information and handled in accordance with the procedures set forth in CEPR-MI-2016-0009 as currently amended and may be amended from time to time. The analysis shall provide operational criteria, define Ancillary Services requirements, and demonstrate least-cost mitigation solutions to maintain system stability;

c) The IRP shall identify thermal and voltage reliability issues in PREPA's transmission system and distribution systems. Such information shall be treated as Critical Energy Infrastructure Information and handled in accordance with the procedures set forth in CEPR-MI-2016-0009 as currently amended and may be amended from time to time;

d) The IRP shall identify transmission, distribution, and substation potential improvements to increase reliability and meet minimum transmission standards;

e) The IRP shall document the transmission and distribution implications of the Preferred Resource Plan, including assessing if the plan requires incremental transmission or distribution mitigation or changes.

K) Action Plan- The purpose of the Action Plan is to specify implementation actions that need to be performed during the first five years of the Planning Period as a result of the Preferred Resource Plan. The Action Plan is not intended to replace or modify additional resource certification processes required by statute or other Commission rules and orders.

1) Action Plan Documentation- The Action Plan shall include a table of key actions in the first five years after approval of the IRP including, at a minimum, expected procurement processes for supply-side resources and energy efficiency, permitting requirements, construction activities, required studies, and other significant events. The Action Plan shall cover intended acquisitions of demand-side, supply-side, transmission, distribution, and/or fuel infrastructure resources; retirements and/or retrofits of existing generating resources; entrance into, renegotiation or cessation of power purchase agreements; and any other resource commitments.

   a) For each action, the IRP shall specify and provide:

      i. The expected calendar year and quarter in which the action will be commenced;

      ii. The expected calendar year and quarter in which the action will be completed;

      iii. Issuances of permits and other regulatory actions that are required in order for the resource action to take place.

      iv. For any major expected resource acquisitions, retirements, retrofits or power purchase agreements, the action plan shall provide information on the cost of the option chosen and the plan for financing that option.

      v. The anticipated impact of the resource action on any relevant Performance Metrics established by the Commission as described in Section 5.01.

      vi. Any other information required by the Commission through resolution or order.

2) Action Plan Development.

   a) The Action Plan shall be based on the Preferred Resource Plan described in subsection (H)(2)(d) above.

   b) The Action Plan shall cover a period of no less than five (5) years from the date of filing of the IRP. Information shall be provided for any activities that are or will be underway or planned to take place within the Action Plan period.

   c) The Action Plan shall account for environmental impacts and shall discuss the plans to meet environmental regulatory requirements at existing resources subject to such requirements.

d) The Action Plan shall comply with all laws and regulations enacted that address requirements for demand-side resources and supply-side resources, including but not limited to Act 82-2010.

e) Any given Action Plan will remain in effect until a new Action Plan is approved as part of a subsequent IRP proceeding or until the Commission states otherwise.

L) Prior Action Plan Implementation Status Update- The IRP shall provide a status update on the implementation of the Action Plan in effect at the time of the filing of the IRP (or the most recent Action Plan, if the filing of a proposed IRP occurs after the expiration of any previous Action Plan). This status update shall include the following:

1) An itemized list of each element of the prior IRP Action Plan;

2) A description of PREPA actions taken to execute each action item;

3) Any changes to date in the timeframe of expected commencement and completion, permitting or regulatory requirements, or removal of the action item based on intervening events;

4) Any changes to permitting, engineering or construction processes of Major Projects already in progress; and

5) A description of the cause of any changes to the prior IRP Action Plan.

M) Renewable Energy Project Status Update- The IRP shall include an assessment of new and contracted renewable energy projects, and PREPA's expected ability to meet renewable portfolio standard targets. This update shall be comprised of the following:

1) An itemized list of each new renewable energy project under contract but not yet built at the time of the IRP filing. For each project, the IRP shall identify:

a) If the project was included as an existing resource in the IRP filing;

b) If the project was included as a likely new resource in the IRP filing, and the expected online year;

c) PREPA's contracted energy price for the project, including any applicable price escalators;

d) Any other expected payments to be made by PREPA for the project, including renewable energy supplemental payments, capacity payments, or fixed charges, and a description of the price and price structure for such payments;

e) The contracting, permitting, financing and construction stage of the project; and

f) PREPA's assessment of the likelihood of project completion.

2) An assessment of PREPA's expected ability to meet renewable portfolio standard targets, including a table showing PREPA's anticipated compliance position for each year of the Planning Period.

N) Demand-Side Resources Status Update- The IRP shall include an assessment of new and contracted demand-side energy and capacity projects, including energy efficiency, demand-response, distributed generation, and load control programs. This update shall be comprised of an itemized list of each new demand-side resource program under contract but not yet implemented or built at the time of the IRP filing. For each project, the IRP shall list:

1) If the project was included as an existing resource in the IRP filing;

2) If the project was included as a likely new resource in the IRP filing, and the expected online year or expected program operation date;

3) PREPA's contracted energy price for the project, including any applicable price escalators;

4) PREPA's contracted capacity price for the project, including any applicable price escalators;

5) Any other expected payments to be made by PREPA for the project, and a description of the price and price structure for such payments;

6) The contracting, permitting, financing and implementation stage of the project; and

7) PREPA's assessment of the likelihood of project completion.

Section 2.04.- Schedule and Filing.

A) As required by Article 6.23 of Act 57-2014 and Section 6B(h) of Act 83, every three (3) years from the date a Commission-approved IRP is effective and is legally binding, PREPA shall submit for Commission approval an IRP proposal in accordance with the provisions of this Regulation and applicable

Commission resolutions and orders. In the case of a substantial change in the energy demand or group of resources, the Commission may order that the review of the next IRP be carried out before the three (3) years provided in herein to respond to and/or mitigate such changes.

B) When filing an IRP, PREPA shall simultaneously publish on its website a true and exact copy, subject to applicable confidentiality privileges, of the IRP proposal submitted to the Commission.

The filing of the IRP shall initiate a proceeding at the Commission pursuant to the provisions of this Regulation, and to the provisions of Commission Regulation No. 8543. In the event of any discrepancy between the provisions of this Regulation and the provisions of Regulation 8543, the provisions of this Regulation shall prevail.

Section 2.05.- Update, Amendment or Review to an Approved IRP

A) At any moment prior to the 3-year filing requirement for new IRP proposals, PREPA may, submit a proposed update, amendment or review to an approved IRP. Reasons that might warrant PREPA to consider proposing an update, amendment or review to an approved IRP include, but are not limited to:

1) It anticipates submitting an application for a certificate to construct, purchase or otherwise acquire a long-term supply-side or demand-side resource that was not previously included as part of the approved IRP;

2) It anticipates the need to undertake a procurement process for a demand-side or supply-side resource that was not previously included as part of an approved IRP;

3) The data used in the formulation of its approved IRP requires significant modification that affects the choice of a resource contemplated in the approved IRP;

4) It expects to make a Major Change to the Action Plan or Capital Plans before the filing of the next IRP proposal.

B) Notwithstanding paragraph (A) of this Section, the Commission shall have the authority to require PREPA to file an update, amendment or review to the approved IRP, should it determine that conditions warrant such action.

C) In seeking an update, amendment or review to an approved IRP, PREPA must show that the proposed update, amendment or review is the preferred option, taking into account the requirements set forth in Section 2.03(H)(2)(d) of this Regulation.

D) In seeking an update, amendment or review to an approved IRP, PREPA shall propose for Commission review, the components of Section 2.03 of this

Regulation that should be applied to the analysis of the proposed update, amendment or review. The Commission will establish, through resolution or order, the specific components of Section 2.03 that shall apply.

E) The filing of an IRP update does not relieve PREPA from its obligation to file a new, complete IRP every three (3) years from the date of approval of the most recent IRP.

Section 2.06.- Certification of Compliance with Section 6B of Act 83

The IRP shall include a certification regarding PREPA's compliance with the requirements of Section 6B (h)(vi) of Act 83.

ARTICLE III. PROCEDURE BEFORE THE COMMISSION

Section 3.01.- IRP Prefiling Process (Phase 1)

A) When filing a proposed IRP for Commission approval, the following procedures shall be followed:

   1) No less than two years after the approval of the most recent IRP, the Commission may schedule one or more technical conferences to gather information regarding the methodology and contents contemplated by PREPA for its new IRP proposal. In scheduling these technical conferences, the Commission may require PREPA to provide specific information regarding the development of the proposed IRP. The Commission will set forth, in its Orders scheduling the technical conferences, the process for the orderly presentation of information.

   2) The purpose of these technical conferences is to provide an opportunity for the Commission to ensure PREPA's IRP filing will reasonably comply with the requirements set forth in this Regulation and the analysis conducted therein will be sufficiently robust so as to comply with public policy goals and meet Commission expectations as to the quality of the analysis and information provided. These proceedings will also provide an opportunity for PREPA to seek clarifications from the Commission with regards to compliance with the requirements set forth in this Regulation.

B) During the Phase 1 period, the Commission may require PREPA to do the following:

   1) Consider certain plausible scenarios, including but not limited to such matters as changes in environmental regulations, the need for transmission expansion, and, significant changes to fuel prices or customer demand, and

   2) Exclude or expand certain conditions of Section 2.03.

C) The Commission may require PREPA to address any special issues it believes should be included in the IRP that are not specifically set forth in these rules.

Section 3.02 Filing of the IRP (Phase 2)

A) Within thirty (30) days from the date in which PREPA files its proposed IRP, the Commission shall review the IRP filing to determine whether it complies in full with the requirements of this Regulation.

1) If the Commission finds that the IRP filing complies with the requirements of this Regulation, the Commission will issue a resolution indicating that the IRP is complete and that the adjudicative process may begin. A determination of completeness by the Commission shall not be construed as a ruling on the substance of the IRP filing.

2) If the Commission finds that the IRP filing is not in compliance with this Regulation, the Commission will identify the specific areas in which PREPA's filing is deficient and the information required to correct such deficiency. The Commission shall grant a reasonable term for PREPA to refile its proposed IRP.

3) Once PREPA refiles the proposed IRP with the corrections of the identified deficiencies, the Commission shall evaluate such refiling within thirty (30) days to determine if it complies with this Regulation and shall issue any appropriate order or resolution.

4) If the Commission determines that the deficiencies in PREPA's filing are of such nature that correcting them through the process established above is not practical, the Commission may reject PREPA's filing in its entirety.

B) The Commission, at its discretion, may extend its review period to determine whether the IRP filing complies with the requirements of this Regulation.

Section 3.03.- Intervening Parties.

A) Any person may file a petition to intervene in the IRP proceeding within thirty (30) days after the Commission's determination that the proposed IRP is complete. Nevertheless, the Commission shall retain the discretion to grant petitions to intervene filed after the expiration of the 30-day time period.

B) The Commission will address petitions to intervene in accordance with Section 5.05 of Regulation 8543 and Sections 3.5 and 3.6 of Act 38-2017.

Section 3.04.-Initial Technical Hearing.

Within forty-five (45) days from the date PREPA's IRP filing is determined to be complete, the Commission will hold an initial hearing in which PREPA will have the opportunity to present its IRP filing and answer initial questions from the

Commission Staff, its consultants and Intervenors regarding the content of the IRP filing. The initial hearing shall be open for the public to attend.

Section 3.05.- Procedural Calendar.

Within fifteen (15) days from the date PREPA's IRP filing is determined to be complete, the Commission will issue an Order detailing the procedural calendar and any rules governing the proceeding, including, but not limited to, discovery, hearings and, filings and other pleadings.

Section 3.06.- Prefiled Written Direct Testimony

A) The IRP filing shall include a list of each PREPA witness and must identify the portions, chapters, appendix, workpapers, etc. of PREPA's filing that are being supported by the testimony of each of the listed witnesses.

B) Concurrently with the IRP filing, each witness listed pursuant to paragraph (A) of this Section shall file written testimony stating his or her qualifications, educational background, work experience, subject matter that is being addressed, conclusions and recommendations, and the basis for such conclusions and recommendations. Witnesses need not to sign each page of the prefiled written testimony.

C) Each witness' prefiled written testimony must be accompanied by a signed, notarized statement that contains the following declaration: "Affiant, [(witness name)], being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony and the information, documents and workpapers attached thereto and the portions of the IRP filing I am sponsoring constitute the direct testimony of Affiant in the above-styled case. Affiant states that he/she would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein at the time of the filing. Affiant further states that, to the best of his/her knowledge, his/her statements made are true and correct."

D) Prefiled written testimony or accompanying work-papers must contain all analyses, facts and calculations necessary for the Commission to perform a comprehensive analysis and assign it the appropriate probative value.

E) The IRP filing and prefiled written testimony shall avoid generalized or vague statements that would require time-consuming discovery to understand the supporting reasoning or to gather the supporting facts.

Section 3.07.- Publishing of Final IRP Plan on PREPA's Webpage

PREPA shall publish on its website a true and exact copy of the IRP approved by the Commission. This plan must be accessible to the public, free of charge, from the date in which the Commission notifies PREPA of the approval. Notwithstanding the above, PREPA may withhold from publishing on its website those portions of the IRP the

Commission has determined to be confidential or to be Critical Energy Infrastructure Information, pursuant to the procedures set forth in CEPR-MI-2016-0009 as currently amended and may be amended from time to time.

Section 3.08 – Commission Decision

At the conclusion of the evidentiary proceeding, including the filing of final comments and/or oral arguments, the Commission shall issue an order that accepts, rejects, or modifies the IRP in whole or in part. The Commission may also order PREPA to make further modifications to its IRP as specified by the Commission.

CHAPTER III – ENERGY EFFICIENCY, DEMAND RESPONSE AND PERFORMANCE

ARTICLE IV. ENERGY EFFICIENCY AND DEMAND RESPONSE

Section 4.01.- Energy Efficiency and Demand Response Planning and Reporting.

A) Initially, after the effective date of this Regulation, and thereafter, after the determination by the Commission on the IRP, the Commission shall establish through an Order the method to select a third-party administrator that will plan and implement energy efficiency and demand response programs. The third-party administrator shall be contracted by the Commission and shall submit to it their reports thereon. The costs associated with the third-party administrator, including its compensation, as approved by the Commission, as well as the costs related to the implementation of the energy efficiency and demand response programs, will be covered through the electric rates to be approved by the Commission.

B) By the end of the first quarter of each calendar year, the third-party administrator shall file with the Commission any and all Evaluation Measurement and Verification (EM&V) reports that address the energy efficiency and demand response programs implemented during the previous calendar year. The third-party administrator shall file the first EM&V report upon completion of the first full calendar year of energy efficiency and demand response programs. These EM&V reports shall be conducted by independent organizations with expertise in conducting energy efficiency and demand response EM&V studies. The third-party administrator shall spend approximately four to five percent of the total energy efficiency and demand response program budgets on EM&V reports.

C) By the end of the second quarter of each calendar year, the third-party administrator shall file with the Commission an Energy Efficiency and Demand Response Annual Report (EE&DR Annual Report), which shall include detailed information on the historical performance of energy efficiency and demand response programs for the most recent complete calendar year. The third-party administrator shall file the first EE&DR Annual Report upon completion of the first full year of energy efficiency and demand response programs. These Annual Reports shall include at a minimum the following information separately for each energy efficiency and demand response program. This information shall also be aggregated by customer class and for the portfolio of programs as a whole:

1) Costs, broken out by administration costs, marketing and delivery costs, program vendor costs, customer financial incentives, technical or training support offered to customers or other trade allies, customer payments, and other costs;
2) Costs broken down by customer class: residential, commercial, industrial, and governmental.
3) Annual energy savings (measured in MWh) for each year of the Planning Period;
4) Lifetime energy savings (measured in MWh);
5) Peak demand savings (measured in MW) for each year of the Planning Period;
6) Annual cost savings, in dollars ($) for each year of the Planning Period;
7) Quantified non-energy benefits, in dollars ($) for each year of the Planning Period;
8) A discussion of qualitative non-energy benefits;
9) Cumulative present value of program costs and program savings;
10) Net savings, and benefit cost ratio;
11) Eligible customers, program participants, and participation rate, for the past five (5) years in which efficiency programs were delivered and projected for the next three (3) years; and
12) A description of the program, describing the market sector addressed, the customer sector addressed, the delivery mechanism, financial incentives offered to customers, training and technical assistance offered to customers, and other relevant information.

D) By the end of the third quarter of each calendar year, the third-party administrator shall file with the Commission its Energy Efficiency and Demand Response Plan (EE&DR Plan), which shall include its plan for all energy efficiency and demand response programs to be implemented over the next three (3) years. The third-party administrator shall file the first EE&DR Plan with the Commission within 120 days of the start of its contract to implement the energy efficiency and demand response programs, as required by Section 4.01(D) of this Regulation. The EE&DR Plans shall be consistent with the Action Plan of the most recently approved IRP. Any deviations from the most recently approved Action Plan shall be justified with quantitative analyses of economic and other implications of the deviation. The EE&DR Plans shall be designed to enable the third-party administrator to identify and implement all cost-effective energy efficiency and demand response programs, consistent with the most recently approved IRP or any subsequent comparable economic analysis. The EE&DR Plans shall include a proposal for the type and the extent of EM&V reports to prepare for the next three (3) years. The energy efficiency and demand response programs shall conform to best practice program design principles; at a minimum, programs shall:

1) Pass a cost-effectiveness test as designated by the Commission;
2) Address all relevant markets related to efficiency and demand response measures;
3) Serve all customer types;
4) Address all relevant end-uses;
5) Attempt to overcome all relevant market barriers to adoption of energy efficiency and demand response measures;
6) Promote customer equity, both by offering programs to all customer types and by achieving high participation rates across all customers;
7) Ensure that low-income and hard-to-reach customers are marketed and served;
8) Take full advantage of all relevant trade allies to maximize opportunities to market, deliver and install efficiency and demand response measures; and
9) Avoid lost opportunities, which occur when efficiency measures are not installed when it is most cost-effective to do so.

E) The key energy efficiency and demand response programs shall be delivered through third-party contractors. These contractors shall be chosen through a competitive bidding process run by the third party administrator on a periodic basis and approved by the Commission.

F) The third-party administrator shall provide information to PREPA for the purpose of considering energy efficiency and demand response in the development of each IRP. This information shall include the cost and performance of existing energy effcieincy and demand response programs, as well as expected cost and performance of such programs in the future.

ARTICLE V. PERFORMANCE METRICS TARGETS AND INDUCEMENTS

Section 5.01.- Performance Metrics, Targets, and Inducements.

Section 6B (h)(iv) of Act 83 requires PREPA's IRP to include typical performance measures of the electric power industry, and directs PREPA to measure its performance in complying with the mandates of Act 57-2014 in terms of effectiveness and efficiency in providing electric service by conducting a comparative analysis of its performance in relation to the performance of similarly sized and comparable utilities.

The IRP shall include a general narrative of the key performance metrics required by the Commission and also identified in Section 6B(h)(iv) of Act 83, its performance with regards to such metrics and a comparison of its results with those achieved by similarly sized and comparable utilities. Furthermore, as described in Section 2.03(J)(1)(a)(v), PREPA's Action Plan shall include a description of the anticipated impact of each resource action on any applicable performance metrics.

After the determination by the Commission on the first IRP, the Commission opened a docket to establish performance inducement mechanisms (PIMs) that will apply to PREPA. The PIMs shall include performance metrics, performance targets and specific performance inducements, in order to monitor and guide key areas related to PREPA's performance. The Commission will issue a Resolution and Order after the conclusion of the proceeding and will review periodically the performance metrics to determine whether any updates, modifications or refinements are warranted.

Agreed upon by the Puerto Rico Energy Commission, in San Juan, Puerto Rico, on this 20th day of April, 2018.

Ángel R. Rivera de la Cruz
Associate Commissioner

José H. Román Morales
Associate Commissioner
Interim Chairman

Exhibit 3

Minnesota Rules Currentness
Chapter 7843
Public Utilities Commission
Utility Resource Planning Process

Minnesota Rules, part 7843.0100

7843.0100 DEFINITIONS.

Subpart 1. **Scope.** The terms used in parts 7843.0100 to 7843.0600 have the meanings given them in this part.

Subp. 2. **Commission.** “Commission” means the Minnesota Public Utilities Commission.

Subp. 3. **Construction.** “Construction” means significant physical alteration of a site to install or enlarge a major utility facility, but does not include activities incident to preliminary engineering or environmental studies.

Subp. 4. **Contested case proceeding.** “Contested case proceeding” means a resource plan proceeding that has been referred to the Office of Administrative Hearings for proceedings under Minnesota Statutes, sections 14.57 to 14.62.

Subp. 5. **Electric utility.** “Electric utility” means a person, corporation, or other legal entity engaged in generating, transmitting, and selling at retail electricity in Minnesota and whose retail rates are regulated by the commission.

Subp. 6. **Forecast period.** “Forecast period” means the first 15 calendar years following the year the proposed resource plan is filed.

Subp. 7. **Major utility facility.** “Major utility facility” has the meaning given the term in Minnesota Statutes, section 216B.24, subdivision 1.

Subp. 8. **Party.** “Party” means the utility that submitted a specific proposed resource plan or an entity permitted to intervene in the proceeding to evaluate that plan.

Subp. 9. **Resource plan.** “Resource plan” means a set of resource options that a utility could use to meet the service needs of its customers over the forecast period, including an explanation of the supply and demand circumstances under which, and the extent to which, each resource option would be used to meet those service needs. These resource options include using, modifying, and constructing utility plant and equipment; buying power generated by other entities; controlling customer loads; and implementing customer energy conservation.

Subp. 10. **Socioeconomic effects.** “Socioeconomic effects” means changes in the social and economic environments, including, for example, job creation, effects on local economies, geographical concentration of persons and structures, concentration of investment capital, and the ability of low-income and rental households to receive conservation services.

Subp. 11. **Utility.** “Utility” means electric utility.

Credits
Statutory Authority: *MS s 216B.03; 216B.08; 216B.09; 216B.13; 216B.16; 216B.24; 216B.33; 216C.05*

History: *15 SR 336*

Current with amendments received through July 9, 2018

Minnesota Rules, part 7843.0100, MN ADC 7843.0100

End of Document

Minnesota Rules Currentness
Chapter 7843
Public Utilities Commission
Utility Resource Planning Process

Minnesota Rules, part 7843.0200

7843.0200 PURPOSE AND SCOPE.

Subpart 1. **Purpose.** The purpose of parts 7843.0100 to 7843.0600 is to prescribe the contents of and procedures for regulatory review of resource plan filings.

Subp. 2. **Scope.** Parts 7843.0100 to 7843.0600 apply to an electric utility with more than 1,000 retail customers in Minnesota. If the electric utility is part of an entity that also sells or transports gas, parts 7843.0100 to 7843.0600 apply only to the entity's electric operations.

Credits
Statutory Authority: *MS s 216B.03; 216B.08; 216B.09; 216B.13; 216B.16; 216B.24; 216B.33; 216C.05*

History: *15 SR 336*

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Minnesota Rules, part 7843.0200, MN ADC 7843.0200

End of Document

Minnesota Rules Currentness
Chapter 7843
Public Utilities Commission
Utility Resource Planning Process

Minnesota Rules, part 7843.0300

7843.0300 FILING REQUIREMENTS AND PROCEDURES.

Subpart 1. **Procedural rules.** Except as otherwise shown in parts 7843.0100 to 7843.0600, the procedures prescribed by parts 7830.0100 to 7830.4400 apply to resource plan filings.

Subp. 2. **Filing date.** Beginning July 1, 1991, and July 1, 1992, and every two years afterward, an electric utility shall submit a proposed resource plan covering the forecast period. The commission shall designate by order those utilities who shall make their initial filings in 1991 and those who shall make their initial filings in 1992. In deciding between the years for a given utility, the commission shall consider the size of the utility and its likely need for additional resources, including large energy facilities, defined in Minnesota Statutes, section 216B.2421, subdivision 2, and major utility facilities.

Subp. 3. **Completeness of filing.** The resource plan filing must contain the information required by part 7843.0400, unless an exemption has been granted under subpart 4. If the commission determines before September 1 of the filing year that the filed information is incomplete or unclear, it may order the utility to augment or clarify the filing.

This subpart does not limit the right of process participants to submit information requests under subpart 8.

Subp. 4. **Exemptions from data requirements.** Before submitting a proposed resource plan, the utility may be exempted from a data requirement of parts 7843.0100 to 7843.0600 if the utility (1) submits a written request for an exemption from specified rules and (2) shows that the data requirement is unnecessary or may be satisfied by submitting another document. A request for exemption must be filed at least 90 days before the resource plan is due. Interested persons or parties may submit comments on the request within 30 days of the date the request is filed. As soon as practicable, the commission shall provide a written response to the request and include the reasons for its decision.

Subp. 5. **Copies of filings.** A covered utility shall submit 15 copies of its resource plan filing to the commission. The commission may request up to ten additional copies of combined and common filings. A utility shall also provide copies to the Minnesota Department of Commerce, the Residential and Small Business Utilities Division of the Office of the Attorney General, the Minnesota Environmental Quality Board and member agencies, and other interested persons or parties who request copies. A utility shall maintain a distribution list. The list must include the names and addresses of the persons or organizations receiving copies and the number of copies provided. A utility is not required to distribute more than 100 copies. However, a utility shall honor reasonable requests for copies of the nontechnical summary identified in part 7843.0400, subpart 4.

Subp. 6. **Changes to filings.** After the resource plan filing is submitted, each page of a change or correction to a previously filed page must be marked with the word “REVISED” and with the date the revision was made. The utility shall send to persons receiving copies of the resource plan filing a like number of copies of changed or corrected pages.

Subp. 7. **Intervention.** Interested persons may become, or may petition to become, parties under parts 7830.0100 to 7830.4400. The Minnesota Department of Commerce, the Residential and Small Business Utilities Division of the Office of the Attorney General, and the Minnesota Environmental Quality Board may petition as of right in a resource plan proceeding.

"Petition as of right" means a petition for intervention that confers party status upon the petitioner without formal approval from either the commission or an administrative law judge.

The deadline for intervention is November 1 of the year the utility's proposed resource plan is filed. The commission may allow late intervention, upon good cause.

Subp. 8. **Information requests.** The parties shall comply with reasonable requests for information by the commission, other parties, and other interested persons. A copy of an information request must be provided to the commission and to known parties. Parties shall reply to information requests within ten days of receipt, unless this would place an extreme hardship upon the replying party. At least one copy of information provided to a party or other interested person must be filed with the commission. The replying party must also provide a copy of the information to any other party or interested person upon request. Disputes regarding information requests may be taken to the commission or, if a contested case proceeding has been ordered, to the assigned administrative law judge.

Subp. 9. **Uncontested proceeding.** The commission shall conduct the resource planning process as an uncontested proceeding, unless a contested case proceeding is required by statute or constitutional right.

"Uncontested proceeding" means a proceeding before the commission that has not been referred to the Office of Administrative Hearings for proceedings under Minnesota Statutes, sections 14.57 to 14.62.

Subp. 10. **Written comments.** Parties and other interested persons have until November 1 of the filing year to review and comment upon the resource plan filings. The comments may include proposed alternative resource plans described in subpart 11.

Subp. 11. **Proposed alternative resource plans.** Parties and other interested persons may express support for the proposed resource plan filed by a utility. Alternatively, parties and other interested persons may file proposed resource plans different from the plan proposed by the utility. When a plan differs from that submitted by the utility, the plan must be accompanied by a narrative and quantitative discussion of why the proposed changes would be in the public interest, considering the factors listed in part 7843.0500, subpart 3.

Subp. 12. **Response comment period.** Parties and other interested persons may file responses to the comments and to the proposed alternative resource plans of other parties or interested persons from November 1 to December 31 of the filing year.

Subp. 13. **Official service list.** The commission shall maintain an official service list for a resource plan proceeding. The preparer of a filing shall serve copies on persons on the official service list at the time of service, except as provided in subpart 8.

Credits

Statutory Authority: *MS s 216B.03; 216B.08; 216B.09; 216B.13; 216B.16; 216B.24; 216B.33; 216C.05*

History: *15 SR 336; L 2001 1Sp4 art 6 s 1*

Current with amendments received through July 9, 2018

Minnesota Rules, part 7843.0300, MN ADC 7843.0300

End of Document

Minnesota Rules Currentness
Chapter 7843
Public Utilities Commission
Utility Resource Planning Process

Minnesota Rules, part 7843.0400

7843.0400 CONTENTS OF RESOURCE PLAN FILINGS.

Subpart 1. **Advance forecasts.** A utility shall include in the filing identified in subpart 2 its most recent annual submission to the Minnesota Department of Commerce and the Minnesota Environmental Quality Board under Minnesota Statutes, sections 216B.2422, subdivision 2a, and 216C.17, and parts 7610.0100 to 7610.0600.

Subp. 2. **Resource plan.** A utility shall file a proposed plan for meeting the service needs of its customers over the forecast period. The plan must show the resource options the utility believes it might use to meet those needs. The plan must also specify how the implementation and use of those resource options would vary with changes in supply and demand circumstances. The utility is only required to identify a resource option generically, unless a commitment to a specific resource exists at the time of the filing. The utility shall also discuss plans to reduce existing resources through sales, leases, deratings, or retirements.

"Derating" means a temporary or permanent reduction in the expected power output of a generating facility.

Subp. 3. **Supporting information.** A utility shall include in its resource plan filing information supporting selection of the proposed resource plan.

A. When a utility's existing resources are inadequate to meet the projected level of service needs, the supporting information must contain a complete list of resource options considered for addition to the existing resources. At a minimum, the list must include new generating facilities of various types and sizes and with various fuel types, cogeneration, new transmission facilities of various types and sizes, upgrading of existing generation and transmission equipment, life extensions of existing generation and transmission equipment, load-control equipment, utility-sponsored conservation programs, purchases from nonutilities, and purchases from other utilities. The utility may seek additional input from the commission regarding the resource options to be included in the list. For a resource option that could meet a significant part of the need identified by the forecast, the supporting information must include a general evaluation of the option, including its availability, reliability, cost, socioeconomic effects, and environmental effects.

B. The supporting information must include descriptions of the overall process and of the analytical techniques used by the utility to create its proposed resource plan from the available options.

C. The supporting information must include an action plan, a description of the activities the utility intends to undertake to develop or obtain noncurrent resources identified in its proposed plan. The action plan must cover a five-year period beginning with the filing date. The action plan must include a schedule of key activities, including construction and regulatory filings.

D. For the proposed resource plan as a whole, the supporting information must include a narrative and quantitative discussion of why the plan would be in the public interest, considering the factors listed in part 7843.0500, subpart 3.

Subp. 4. **Nontechnical summary.** A utility shall include in its resource plan filing a nontechnical summary, not exceeding 25 pages in length and describing the utility's resource needs, the resource plan created by the utility to meet those needs, the process and analytical techniques used to create the plan, activities required over the next five years to implement the plan, and the likely effect of plan implementation on electric rates and bills.

Subp. 5. **Combined and common filings.** Utilities may combine their individual filings into a single larger filing, as long as the action does not lead to a loss of information. Information common to two or more of the utilities need only be submitted once, as long as the filing clearly shows the utilities to which the information applies.

Credits
Statutory Authority: *MS s 216B.03; 216B.08; 216B.09; 216B.13; 216B.16; 216B.24; 216B.33; 216C.05*

History: *15 SR 336; L 2001 1Sp4 art 6 s 1*

Current with amendments received through July 9, 2018

Minnesota Rules, part 7843.0400, MN ADC 7843.0400

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Minnesota Rules Currentness
Chapter 7843
Public Utilities Commission
Utility Resource Planning Process

Minnesota Rules, part 7843.0500

7843.0500 COMMISSION REVIEW OF RESOURCE PLANS.

Subpart 1. **Decision.** Based upon the record, which is the information filed with the commission in the resource plan proceeding of a utility, including responses to information requests, the commission shall issue a decision consisting of findings of fact and conclusions on the utility's proposed resource plan and the alternative resource plans. If the commission determines there is insufficient information upon which to issue findings and conclusions, it may delay issuing its decision to permit production of the desired type and level of information.

Subp. 2. **Preferred plan.** If the commission concludes that a set of resource options would be optimal, considering the desirable attributes listed in subpart 3, it may identify that set of resource options as a preferred resource plan. A preferred resource plan need not have been specifically proposed or advocated by the utility, an intervening party, or other interested person.

Subp. 3. **Factors to consider.** In issuing its findings of fact and conclusions, the commission shall consider the characteristics of the available resource options and of the proposed plan as a whole. Resource options and resource plans must be evaluated on their ability to:

A. maintain or improve the adequacy and reliability of utility service;

B. keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints;

C. minimize adverse socioeconomic effects and adverse effects upon the environment;

D. enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and

E. limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

Subp. 4. **Issues requiring further consideration.** In its decision, the commission may direct the utility to provide in its next resource plan filing a discussion of specified issues. The issues may include those not totally resolved in the current proceeding and those for which the state of knowledge is changing substantially between resource plan filings.

Subp. 5. **Changed circumstances affecting resource plans.** The utility shall inform the commission and other parties to the last resource plan proceeding of changed circumstances that may significantly influence the selection of resource plans. Upon receiving notice of changed circumstances, the commission shall consider whether additional administrative proceedings are necessary before the utility's next regularly scheduled resource plan proceeding.

Subp. 6. **Authority of other agencies.** Issuance of a resource plan decision by the commission does not limit the statutory authority of other agencies in their regulatory responsibilities.

Credits
Statutory Authority: *MS s 216B.03; 216B.08; 216B.09; 216B.13; 216B.16; 216B.24; 216B.33; 216C.05*

History: *15 SR 336*

Current with amendments received through July 9, 2018

Minnesota Rules, part 7843.0500, MN ADC 7843.0500

End of Document

Minnesota Rules Currentness
Chapter 7843
Public Utilities Commission
Utility Resource Planning Process

Minnesota Rules, part 7843.0600

7843.0600 RELATIONSHIP TO OTHER COMMISSION PROCESSES.

Subpart 1. **Other proceedings begun before plan proceeding completed.** The commission shall not use the resource planning process as a reason to delay unduly the completion of a proceeding begun under other law.

Subp. 2. **Resource plan findings of fact and conclusions.** The findings of fact and conclusions from the commission's decision in a resource plan proceeding may be officially noticed or introduced into evidence in related commission proceedings, including, for example, rate reviews, conservation improvement program appeals, depreciation certifications, security issuances, property transfer requests, cogeneration and small power production filings, and certificate of need cases. In those proceedings, the commission's resource plan decision constitutes prima facie evidence of the facts stated in the decision. This subpart does not prevent an interested person from submitting substantial evidence to rebut the findings and conclusions in another proceeding.

Subp. 3. **Construction of major utility facilities.** A utility submitting a proposed resource plan is exempt from the requirements of other rules covering construction of major utility facilities and adopted under Minnesota Statutes, section 216B.24. The exemption does not constitute a waiver of the commission's right to review the prudence of the construction or planning in later resource plan and general rate case proceedings.

Subp. 4. **Exemption from filing when certificate of need proceeding initiated.** The commission shall grant an exemption from the filing requirements of parts 7843.0100 to 7843.0600 if the conditions in items A to E are met:

A. The utility plans to submit a certificate of need application under Minnesota Statutes, section 216B.243.

B. The utility submits a written request for an exemption that indicates the utility's intent to apply for a certificate of need, the size and type of facility for which certification will be sought, the projected application date, and the utility's willingness to submit all the information required by part 7843.0400, subparts 1 to 4, with the certificate of need application. The request must be filed by April 1 of the filing year and at least 90 days before the projected filing date for the certificate of need application.

C. The utility agrees that, if the exemption is granted and it fails to submit the certificate of need application by the projected application date, it will submit either the certificate of need application or a resource plan filing within 60 days of the projected application date or by July 1, whichever is later.

D. The commission determines that the utility's filings in the anticipated certificate of need proceeding will provide the information needed to issue a decision and select a preferred resource plan under part 7843.0500. In deciding whether the certificate of need filings will provide the necessary information, the commission shall consider factors such as the size and type of facility for which the certificate of need is sought.

E. The commission determines that the exemption will foster administrative efficiency, considering:

(1) the extent and consequences of any delay in the receipt of information that will result from the exemption; and

(2) the likelihood and extent of administrative cost savings that may result from the exemption.

Credits

Statutory Authority: *MS s 216B.03; 216B.08; 216B.09; 216B.13; 216B.16; 216B.24; 216B.33; 216C.05*

History: *15 SR 336*

Current with amendments received through July 9, 2018

Minnesota Rules, part 7843.0600, MN ADC 7843.0600

Exhibit 4

2007 WL 534555 (Or.P.U.C.)
Slip Copy

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON

07-047
UM 1056

Synopsis
Investigation Into Integrated Resource Planning.

Oregon Public Utility Commission

ENTERED February 09, 2007
ERRATA ORDER

BY THE COMMISSION:

DISPOSITION: APPENDIX TO ORDER NO. 07-002 CORRECTED

***1** In Order No. 07-002, we adopted guidelines to govern the Integrated Resource Planning (IRP) process. In setting forth those guidelines in an appendix, we inadvertently omitted Guideline 1(d), which we discussed and adopted in the body of the order on pages 7 and 8. Accordingly, Appendix A to Order No. 07-002 is replaced with the attached appendix to this order, which includes all the adopted guidelines. The remainder of the order is unchanged.

IT IS SO ORDERED.

Made, entered, and effective FEB 09 2007.

Lee Beyer Chairman

John Savage Commissioner

Ray Baum Commissioner

APPENDIX A

Adopted IRP Guidelines

Guideline 1: Substantive Requirements

a. All resources must be evaluated on a consistent and comparable basis.
• All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power or gas purchases, transportation, and storage and demand-side options which focus on conservation and demand response.

• Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.

• Consistent assumptions and methods should be used for evaluation of all resources.

• *The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.*

b. Risk and uncertainty must be considered.

• *At a minimum, utilities should address the following sources of risk and uncertainty:*

1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.

2. Natural gas utilities: demand (peak, swing and base-load), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.

• *Utilities should identify in their plans any additional sources of risk and uncertainty.*

c. The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.

• *The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.*
• *Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.*

***2** • *To address risk, the plan should include, at a minimum:*

1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.

2. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.

• *The utility should explain in its plan how its resource choices appropriately balance cost and risk.*

d. The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.

Guideline 2: Procedural Requirements.

a. The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.
b. While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.

c. The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.

Guideline 3: Plan Filing, Review, and Updates.

a. A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.
b. The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.

c. Commission staff and parties should complete their comments and recommendations within six months of IRP filing.

d. The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.

e. The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.

f. Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.

***3** *g. Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:*

• *Describes what actions the utility has taken to implement the plan;*

• *Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and*

• *Justifies any deviations from the acknowledged action plan.*

Guideline 4: Plan Components.

At a minimum, the plan must include the following elements:
a. An explanation of how the utility met each of the substantive and procedural requirements;

b. Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;

c. For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested;

d. For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources;

e. Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;

f. Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;

g. Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;

h. Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations system-wide or delivered to a specific portion of the system;

i. Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;

j. Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;

k. Analysis of the uncertainties associated with each portfolio evaluated;

l. Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers;

m. Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation; and

***4** *n. An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.*

Guideline 5: Transmission.

Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.

Guideline 6: Conservation.

a. Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.
b. To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.

c. To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:

• Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and

• Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.

Guideline 7: Demand Response.

Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).

Guideline 8: Environmental Costs.

Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential CO_2 regulatory costs in Order No. 93-695, from zero to $40 (1990 $). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable.

Guideline 9: Direct Access Loads.

An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.

Guideline 10: Multi-state Utilities.

Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.

Guideline 11: Reliability.

***5** *Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.*

Guideline 12: Distributed Generation.

Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.

Guideline 13: Resource Acquisition.

a. An electric utility should, in its IRP:

• Identify its proposed acquisition strategy for each resource in its action plan.

• Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.

• Identify any Benchmark Resources it plans to consider in competitive bidding.

b. Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.

Footnotes

1 We sometimes refer to this portfolio as the "best cost/risk portfolio.

End of Document

Exhibit 5

West's Arkansas Administrative Code
Title 126. Public Service Commission
Division 03. Utilities Division
Rule 22. Resource Planning Guidelines for Electric Utilities

Ark. Admin. Code 126.03.22-1
Alternatively cited as AR ADC 126 03 025

126.03.22-1. Purpose of Guidelines.

Currentness

Electric utilities regulated by the Arkansas Public Service Commission will use these Guidelines to establish the informational report that will meet the planning expectations of the Commission. The general approach of the Guidelines will allow utilities to formulate plans that reflect their specific circumstances.

Current with amendments received through June 30, 2018.

Ark. Admin. Code 126.03.22-1, AR ADC 126.03.22-1

End of Document

West's Arkansas Administrative Code
Title 126. Public Service Commission
Division 03. Utilities Division
Rule 22. Resource Planning Guidelines for Electric Utilities

Ark. Admin. Code 126.03.22-2
Alternatively cited as AR ADC 126 03 025

126.03.22-2. Resource Planning Defined.

Currentness

Resource planning is a utility planning process which requires consideration of all reasonable resources for meeting the demand for a utility's product, including those which focus on traditional supply sources and those which focus on conservation and the management of demand. The process results in the selection of that portfolio of resources which best meets the identified objectives while balancing the outcome of expected impacts and risks for society over the long run. The resource planning process should define and assess costs and benefits as they appear in the market, including known and identifiable social and environmental costs. Significant non-monetized social and environmental effects should be identified. They need not be monetized as a future risk factor, but they may. The resource planning process should be associated with efforts to augment traditional regulatory review with both regional planning information and cooperative stakeholder consensus building in the preparation of utility plans.

Current with amendments received through June 30, 2018.

Ark. Admin. Code 126.03.22-2, AR ADC 126.03.22-2

End of Document

West's Arkansas Administrative Code
Title 126. Public Service Commission
Division 03. Utilities Division
Rule 22. Resource Planning Guidelines for Electric Utilities

Ark. Admin. Code 126.03.22-3
Alternatively cited as AR ADC 126 03 025

126.03.22-3. Relationship of the Commission and Utilities with Resource Planning.

Currentness

Resource planning under these Guidelines does not change the fundamental regulatory relationship between the utilities and the Commission. Resource Planning Guidelines do not mandate a specific outcome nor do they mandate specific investment decisions. Resource planning should reflect each utility's unique circumstances and the judgment of its management, who will continue to bear full responsibility for the consequences of their decisions. Resource planning will be relevant to future resource investment decisions and approval proceedings, as well as revenue requirements and rate design. Consistency of a utility's Resource Plan with the Guidelines will be an additional factor for the Commission to consider in evaluating the prudence of investments, construction and rate applications, as will changed circumstances and other evidence.

Current with amendments received through June 30, 2018.

Ark. Admin. Code 126.03.22-3, AR ADC 126.03.22-3

End of Document

West's Arkansas Administrative Code
Title 126. Public Service Commission
Division 03. Utilities Division
Rule 22. Resource Planning Guidelines for Electric Utilities

Ark. Admin. Code 126.03.22-4
Alternatively cited as AR ADC 126 03 025

126.03.22-4. General Guidelines.

Currentness

A Resource Plan must contain certain elements. Sections 4.1 - 4.8 are the Guidelines the Commission will use to review the completeness of the efforts to produce the utility Resource Plan. The Resource Plan shall be submitted to the Commission for informational purposes.

4.1 Objectives

The utility shall clearly state and support its objectives. The objectives of the Resource Plan include, but are not limited to, low cost, adequate and reliable energy services; economic efficiency; financial integrity of the utility; comparable consideration of demand and supply resources; mitigation of risks; consideration of environmental impacts; and consistency with governmental regulations and policies. In meeting the objectives, the utility should put itself in a position to respond to anticipated economic conditions and technological advancements and changes, including environmental requirements.

4.2 Development of a Range of Demand Forecasts

A reasonable set of assumptions for econometric and/or end use variables should be considered in the development of a range of outcomes that complement the long-term forecasts of electricity demand (MW) and energy consumption (kWh). A minimum of 10 years should be used as a planning horizon. Energy usage by customer class should be separately identified.

4.3 Identifying and Characterizing Supply and Demand Resources

The utility should assess existing resources based on their cost effectiveness and considering the utility's planning objectives. For incremental capacity needs, all reasonably useful and economic supply and demand resources that may be available to a utility or its customers should be considered. Utility efforts to encourage energy efficiency, conservation, demand-side management, interruptible load, and price responsive demand should be identified. Identified resources should be investigated to determine costs, effectiveness, and other attributes such as potential future emission control or allowance costs to the extent they are monetizable. Non-monetizable costs and benefits should be recognized. Cost effective resources that do not meet minimum criteria such as risk or environmental or other governmental rules or policy should be eliminated from further consideration in this planning cycle.

4.4 Development of Multiple Integrated Resource Portfolios

The planning process should identify multiple integrated resource portfolios, each of which meets reliability criteria. Utilities will identify and take into consideration risk in developing these different portfolios, such as different levels of load growth, different fuel cost forecasts, or other parameters that are influenced by conditions beyond the utility's control. The portfolios should be compared on the present value of the cost of each.

4.5 Evaluation and Selection of the Utility's Resource Plan

The utility shall identify a preferred Resource Plan that provides a balance of risks of adverse outcomes to its customers and its own financial integrity, while providing flexibility to change as future conditions warrant. The evaluation should fully describe how the utility's preferred plan affects long term utility resource needs and costs.

4.6 The Action Plan

The utility shall submit an action plan consisting of the tasks that are necessary to implement the preferred Resource Plan. The action plan shall include a description of and timeline associated with the utility's competitive bidding process. A self-build option must be compared to market opportunities. The process for the acquisition and approval of resources described in the action plan is separate from the information provided regarding the resource planning process described herein.

4.7 Transmission Plan

The transmission plan necessarily results from a separate planning process and is a separate plan; however, it should be integrated into the overall resource planning process, such that the analysis of generation options and demand response options can be synthesized and optimized. Transmission planning will be done by an independent entity and is regional in scope.

4.8 Stakeholder process

Each utility will organize and facilitate meetings of a Stakeholder Committee for resource planning purposes. The Stakeholder Committee should be broadly representative of retail and wholesale customers, independent power suppliers, marketers, and other interested entities in the service area. The Stakeholders shall develop their own rules and procedures. Stakeholders should review utility objectives, assumptions, and estimated needs early in the planning cycle. The utility shall make a good faith effort to properly inform and respond to the Stakeholder Committee. A Report of the Stakeholder Committee should be included with the Resource Plan submittal. Stakeholders and General Staff may also submit comments to the Commission on each Resource Plan after it has been submitted by the utility. Such comments should be taken into consideration by the utility in its preparation efforts and decisions concerning subsequent approval applications, as well as in its next planning cycle. If comments concerning the process and results warrant, the Commission may require the utility to re-evaluate and resubmit its Resource Plan for the current planning cycle to address concerns raised in the comments.

Current with amendments received through June 30, 2018.

Ark. Admin. Code 126.03.22-4, AR ADC 126.03.22-4

End of Document

West's Arkansas Administrative Code
Title 126. Public Service Commission
Division 03. Utilities Division
Rule 22. Resource Planning Guidelines for Electric Utilities

Ark. Admin. Code 126.03.22-5
Alternatively cited as AR ADC 126 03 025

126.03.22-5. Implementing Report.

Currentness

At approximately the mid-point of the utility's planning cycle, a short written report on the progress and success (or not) of implementing the Resource Plan should be submitted to the Commission.

Current with amendments received through June 30, 2018.

Ark. Admin. Code 126.03.22-5, AR ADC 126.03.22-5

End of Document

West's Arkansas Administrative Code
Title 126. Public Service Commission
Division 03. Utilities Division
Rule 22. Resource Planning Guidelines for Electric Utilities

Ark. Admin. Code 126.03.22-6
Alternatively cited as AR ADC 126 03 025

126.03.22-6. Scheduling and Compliance Requirements.

Currentness

6.1 Scheduling

Each utility should determine the term of its resource planning cycle, from one to three years, and schedule its submission with the Commission. However, a Resource Plan shall be submitted at least once in each three-year period.

6.2 Compliance Requirements

Within thirty (30) days of the date of the Order approving these Guidelines, each electric utility shall submit to the Commission a copy of its currently effective Resource Plan that has heretofore served as the basis for its short, intermediate, and long-term resource acquisition and construction plans as well as a separate Status Report, detailing the precise status of such Resource Plan. At the same time each electric utility also shall advise the Commission in writing of its proposed timeline in which it will comply with the provisions of these Guidelines, or alternatively explain in detail why it believes that its current resource planning process already substantially complies with these Guidelines. The Commission reserves the right to issue subsequent orders setting forth utility-specific procedural schedules for filings and other informational reports in order to ensure compliance with these Guidelines.

Current with amendments received through June 30, 2018.

Ark. Admin. Code 126.03.22-6, AR ADC 126.03.22-6

End of Document

Exhibit 6

4 CCR 723-3:3600
Alternatively cited as 4 CO ADC 723-3

723-3:3600. Applicability.

Currentness

This rule shall apply to all jurisdictional electric utilities in the state of Colorado that are subject to the Commission's regulatory authority. Cooperative electric associations engaged in the distribution of electricity (i.e., rural electric associations) are exempt from these rules. Cooperative electric generation and transmission associations are subject only to reporting requirements as specified in rule 3605.

Credits
Amended Dec. 30, 2010; Oct. 30, 2011; May 15, 2016.

Current through CR, Vol. 41, No. 13, July 10, 2018.

4 CCR 723-3:3600, 4 CO ADC 723-3:3600

End of Document

West's Colorado Administrative Code
Title 700. Department of Regulatory Agencies
723. Public Utilities Commission
4 CCR 723-3. Rules Regulating Electric Utilities (Refs & Annos)
Electric Resource Planning

4 CCR 723-3:3601
Alternatively cited as 4 CO ADC 723-3

723-3:3601. Overview and Purpose.

Currentness

The purpose of these rules is to establish a process to determine the need for additional electric resources by electric utilities subject to the Commission's jurisdiction and to develop cost-effective resource portfolios to meet such need reliably. It is the policy of the state of Colorado that a primary goal of electric utility resource planning is to minimize the net present value of revenue requirements. It is also the policy of the state of Colorado that the Commission gives the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies.

Credits
Amended Dec. 30, 2010; Oct. 30, 2011; May 15, 2016.

Current through CR, Vol. 41, No. 13, July 10, 2018.

4 CCR 723-3:3601, 4 CO ADC 723-3:3601

End of Document

4 CCR 723-3:3602
Alternatively cited as 4 CO ADC 723-3

723-3:3602. Definitions.

Currentness

The following definitions apply to rules 3600 through 3619. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Availability factor" means the ratio of the time a generating facility is available to produce energy at its rated capacity, to the total amount of time in the period being measured.

(b) "Annual capacity factor" means the ratio of the net energy produced by a generating facility in a year, to the amount of energy that could have been produced if the facility operated continuously at full capacity year round.

(c) "Cost-effective resource plan" means a designated combination of new resources that the Commission determines can be acquired at a reasonable cost and rate impact.

(d) "Demand-side resources" means energy efficiency, energy conservation, load management, and demand response or any combination of these measures.

(e) "End-use" means the light, heat, cooling, refrigeration, motor drive, or other useful work produced by equipment that uses electricity or its substitutes.

(f) "Energy conservation" means the decrease in electricity requirements of specific customers during any selected time period, resulting in a reduction in end-use services.

(g) "Energy efficiency" means the decrease in electricity requirements of specific customers during any selected period with end-use services of such customers held constant.

(h) "Heat rate" means the ratio of energy inputs used by a generating facility expressed in BTUs (British Thermal Units), to the energy output of that facility expressed in kWh.

(i) "Modeling error or omission" means any incorrect, incomplete, or improper input to computer-based modeling performed by the utility, for evaluating a proposed resource, of a magnitude that alters the model results.

(j) "Net present value of revenue requirements" means the current worth of the total expected future revenue requirements associated with a particular resource portfolio, expressed in dollars in the year the plan is filed as discounted by the appropriate discount rate.

(k) "Planning period" means the future period for which a utility develops its plan, and the period, over which net present value of revenue requirements for resources are calculated. For purposes of this rule, the planning period is twenty to forty years and begins from the date the utility files its plan with the Commission.

(l) "Potential resource" means an electric generation facility bid into a competitive acquisition process in accordance with an approved resource plan.

(m) "Renewable energy resources" means all renewable energy resources as defined in the Commission's RES Rules.

(n) "Resource acquisition period" means the first six to ten years of the planning period, in which the utility acquires specific resources to meet projected electric system demand and energy requirements. The resource acquisition period begins from the date the utility files its plan with the Commission.

(o) "Resource plan" or "plan" means a utility plan consisting of the elements set forth in rule 3604.

(p) "Resources" means supply-side resources and demand-side resources used to meet electric system requirements.

(q) "Section 123 resources" means new energy technology or demonstration projects, including new clean energy or energy-efficient technologies under § 40-2-123(1)(a), C.R.S. and § 40-2-123(1)(c), C.R.S., and Integrated Gasification Combined Cycle projects under § 40-2-123(2), C.R.S.

(r) "Supply-side resources" means resources that provide electrical energy or capacity to the utility. Supply-side resources include utility owned generating facilities and energy or capacity purchased from other utilities and non-utilities.

(s) "Typical day load pattern" means the electric demand placed on the utility's system for each hour of the day.

Credits

Amended Dec. 30, 2010; Oct. 30, 2011; Jan. 14, 2012; May 15, 2016.

Current through CR, Vol. 41, No. 13, July 10, 2018.

4 CCR 723-3:3602, 4 CO ADC 723-3:3602

End of Document

West's Colorado Administrative Code
Title 700. Department of Regulatory Agencies
723. Public Utilities Commission
4 CCR 723-3. Rules Regulating Electric Utilities (Refs & Annos)
Electric Resource Planning

4 CCR 723-3:3603
Alternatively cited as 4 CO ADC 723-3

723-3:3603. Resource Plan Filing Requirements.

Currentness

(a) Jurisdictional electric utilities shall file a resource plan pursuant to these rules every four years beginning October 31, 2015. In addition to the required four-year cycle, a utility may file an interim plan, pursuant to rule 3604. If a utility chooses to file an interim plan more frequently than the required four-year cycle, its application must state the reasons and changed circumstances that justify the interim filing.

(b) Each jurisdictional electric utility shall contemporaneously file with its resource plan submitted under paragraph 3603(a), a motion or motions seeking extraordinary protection of information listed as highly confidential pursuant to paragraph 3604(j) and consistent with rule 1101 of the Commission's Rules of Practice and Procedure. The utility shall specifically address appropriate confidentiality protections and nondisclosure requirements for modeling inputs and assumptions that may be used to evaluate a potential resource and that reasonably relate to that facility. The utility's motion or motions shall specify that response time shall run concurrently with the intervention deadline established in the resource plan proceeding. Finally, during the course of the resource plan proceeding, a utility may file additional motions seeking extraordinary protection of information for good cause shown.

Credits
Amended Dec. 30, 2010; Oct. 30, 2011; May 15, 2016.

Current through CR, Vol. 41, No. 13, July 10, 2018.

4 CCR 723-3:3603, 4 CO ADC 723-3:3603

End of Document

West's Colorado Administrative Code
Title 700. Department of Regulatory Agencies
723. Public Utilities Commission
4 CCR 723-3. Rules Regulating Electric Utilities (Refs & Annos)
Electric Resource Planning

4 CCR 723-3:3604
Alternatively cited as 4 CO ADC 723-3

723-3:3604. Contents of the Resource Plan.

Currentness

The utility shall file a plan with the Commission that contains the information specified below. When required by the Commission, the utility shall provide work-papers to support the information contained in the plan. The plan shall include the following.

(a) A statement of the utility-specified resource acquisition period and planning period. The utility shall consistently use the specified resource acquisition and planning periods throughout the entire resource plan and resource acquisition process. The utility shall include a detailed explanation as to why the specific period lengths were chosen in light of the assessment of the needs of the utility system.

(b) An annual electric demand and energy forecast developed pursuant to rule 3606.

(c) An evaluation of existing resources developed pursuant to rule 3607.

(d) An evaluation of transmission resources pursuant to rule 3608.

(e) An assessment of planning reserve margins and contingency plans for the acquisition of additional resources developed pursuant to rule 3609.

(f) An assessment of the need for additional resources developed pursuant to rule 3610.

(g) The utility's plan for acquiring these resources pursuant to rule 3611, including a description of the projected emissions, in terms of pounds per MWH and short-tons per year, of sulfur dioxide, nitrogen oxides, particulate matter, mercury and carbon dioxide for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its resource plan.

(h) The annual water consumption for each of the utility's existing generation resources, and the water intensity (in gallons per MWH) of the existing generating system as a whole, as well as the projected water consumption for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its resource plan.

(i) The proposed RFP(s) the utility intends to use to solicit bids for energy and capacity resources to be acquired through a competitive acquisition process, including model contracts, pursuant to rule 3616.

(j) A list of the information related to the resource plan proceeding that the utility claims is confidential and a list of the information related to the resource plan proceeding that the utility claims is highly confidential. The utility shall also list the information that it will provide to owners or developers of a potential resource under paragraphs 3613(a) and (b). The utility shall further explicitly list the protections it proposes for bid prices, other bid details, information concerning a new resource that the utility proposes to build and own as a rate base investment, other modeling inputs and assumptions, and the results of bid evaluation and selection. The protections sought by the utility for these items shall be specified in the motion(s) submitted under paragraph 3603(b). For good cause shown the utility may seek to protect additional information as confidential or highly confidential by filing the appropriate motion under rule 1101 of the Commission's Rules of Practice and Procedure in a timely manner.

(k) Descriptions of at least three alternate plans that can be used to represent the costs and benefits from increasing amounts of renewable energy resources, demand-side resources, or Section 123 resources as defined in paragraph 3602(q) potentially included in a cost-effective resource plan. One of the alternate plans shall represent a baseline case that describes the costs and benefits of the new utility resources required to meet the utility's needs during the planning period that minimize the net present value of revenue requirements and that complies with the RES, 4 CCR 723-3-3650, et seq., as well as with the demand-side resource requirements under § 40-3.2-104, C.R.S. The other alternate plans shall represent alternative combinations of resources that meet the same resource needs as the baseline case but that include proportionately more renewable energy resources, demand-side resources, or Section 123 resources. The utility shall propose a range of possible future scenarios and input sensitivities for the purpose of testing the robustness of the alternate plans under various parameters.

(l) An assessment of the costs and benefits of the integration of intermittent renewable energy resources on the utility's system, including peer-reviewed studies, consistent with the amounts of renewable energy resources the utility proposes to acquire.

Credits

Amended Dec. 30, 2010; Oct. 30, 2011; Jan. 14, 2012; May 15, 2016.

Current through CR, Vol. 41, No. 13, July 10, 2018.

4 CCR 723-3:3604, 4 CO ADC 723-3:3604

End of Document

West's Colorado Administrative Code
Title 700. Department of Regulatory Agencies
723. Public Utilities Commission
4 CCR 723-3. Rules Regulating Electric Utilities (Refs & Annos)
Electric Resource Planning

4 CCR 723-3:3605
Alternatively cited as 4 CO ADC 723-3

723-3:3605. Cooperative Electric Generation and Transmission Association Reporting Requirements.

Currentness

Pursuant to the schedule established in rule 3603, each cooperative electric generation and transmission association shall report its forecasts, existing resource assessment, planning reserves, and needs assessment, consistent with the requirements specified in rules 3606, 3607, 3609(a) and 3610. Each cooperative generation and transmission association shall also file annual reports pursuant to subparagraphs (a)(I) through (a)(VI) of rule 3618.

Credits
Amended Dec. 30, 2010; Oct. 30, 2011; May 15, 2016.

Current through CR, Vol. 41, No. 13, July 10, 2018.

4 CCR 723-3:3605, 4 CO ADC 723-3:3605

End of Document

West's Colorado Administrative Code
Title 700. Department of Regulatory Agencies
723. Public Utilities Commission
4 CCR 723-3. Rules Regulating Electric Utilities (Refs & Annos)
Electric Resource Planning

4 CCR 723-3:3606
Alternatively cited as 4 CO ADC 723-3

723-3:3606. Electric Energy and Demand Forecasts.

Currentness

(a) Forecast requirements. The utility shall prepare the following energy and demand forecasts for each year within the planning period.

(I) Annual sales of energy and coincident summer and winter peak demand in total and disaggregated among Commission jurisdictional sales, FERC jurisdictional sales, and sales subject to the jurisdiction of other states.

(II) Annual sales of energy and coincident summer and winter peak demand on a system wide basis for each major customer class.

(III) Annual energy and capacity sales to other utilities; and capacity sales to other utilities at the time of coincident summer and winter peak demand.

(IV) Annual intra-utility energy and capacity use at the time of coincident summer and winter peak demand.

(V) Annual system losses and the allocation of such losses to the transmission and distribution components of the system. Coincident summer and winter peak system losses and the allocation of such losses to the transmission and distribution components of the systems.

(VI) Typical day load patterns on a system-wide basis for each major customer class. This information shall be provided for peak-day, average-day, and representative off-peak days for each calendar month.

(b) Range of forecasts. The utility shall develop and justify a range of forecasts of coincident summer and winter peak demand and energy sales that its system may reasonably be required to serve during the planning period. The range shall include base case, high, and low forecast scenarios of coincident summer and winter peak demand and energy sales, based on alternative assumptions about the determinants of coincident summer and winter peak demand and energy sales during the planning period.

(c) Required detail.

(I) In preparing forecasts, the utility shall develop forecasts of energy sales and coincident summer and winter peak demand for each major customer class. The utility shall use end-use, econometric or other supportable methodology as the basis for these forecasts. If the utility determines not to use end-use analysis, it shall explain the reason for its determination as well as the rationale for its chosen alternative methodology.

(II) The utility shall maintain, as confidential, information reflecting historical and forecasted demand and energy use for individual customers in those cases when an individual customer is responsible for the majority of the demand and energy used by a particular rate class. However, when necessary in the resource plan proceedings, such information may be disclosed to parties who intervene in accordance with the terms of non-disclosure agreements approved by the Commission and executed by the parties seeking disclosure.

(d) Historical data. The utility shall compare the annual forecast of coincident summer and winter peak demand and energy sales made by the utility to the actual coincident peak demand and energy sales experienced by the utility for the five years preceding the year in which the plan under consideration is filed. In addition, the utility shall compare the annual forecasts in its most recently filed resource plan to the annual forecasts in the current resource plan.

(e) Description and justification. The utility shall fully explain, justify, and document the data, assumptions, methodologies, models, determinants, and any other inputs upon which it relied to develop its coincident peak demand and energy sales forecasts pursuant to this rule, as well as the forecasts themselves.

(f) Format and graphical presentation of data. The utility shall include graphical presentation of the data to make the data more understandable to the public, and shall make the data available to requesting parties in such electronic formats as the Commission shall reasonably require.

Credits

Amended Dec. 30, 2010; May 15, 2016.

Current through CR, Vol. 41, No. 13, July 10, 2018.

4 CCR 723-3:3606, 4 CO ADC 723-3:3606

End of Document

4 CCR 723-3:3607
Alternatively cited as 4 CO ADC 723-3

723-3:3607. Evaluation of Existing Resources.

Currentness

(a) Existing generation resource assessment. The utility shall describe its existing resources, all utility-owned generating facilities for which the utility has obtained a CPCN from the Commission pursuant to § 40-5-101, C.R.S., at the time the plan is filed, and existing or future purchases from other utilities or non-utilities pursuant to agreements effective at the time the plan is filed. The description shall include, when applicable, the following.

(I) Name(s) and location(s) of utility-owned generation facilities.

(II) Rated capacity and net dependable capacity of utility-owned generation facilities.

(III) Fuel type, heat rates, annual capacity factors and availability factors projected for utility-owned generation facilities over the resource acquisition period.

(IV) Estimated in-service dates for utility-owned generation facilities for which a CPCN has been granted but which are not in service at the time the plan under consideration is filed.

(V) Estimated remaining useful lives of existing generation facilities without significant new investment or maintenance expense.

(VI) The amount of capacity, energy, and demand-side resources purchased from utilities and non-utilities, the duration of such purchase contracts and a description of any contract provisions that allow for modification of the amount of capacity and energy purchased pursuant to such contracts.

(VII) The amount of capacity and energy provided pursuant to wheeling or coordination agreements, the duration of such wheeling or coordination agreements, and a description of any contract provisions that allow for modification of the amount of capacity and energy provided pursuant to such wheeling or coordination agreements.

(VIII) The projected emissions, in terms of pounds per MWH and short-tons per year, of sulfur dioxide, nitrogen oxides, particulate matter, mercury and carbon dioxide for the resources identified under this paragraph 3607(a).

(IX) The expected demand-side resources during the resource planning period from existing measures installed through utility-administered programs; and, from measures expected to be installed in the future through utility-administered programs in accordance with a Commission-approved plan.

(b) Utilities required to comply with these rules shall coordinate their plan filings such that the amount of electricity purchases and sales between utilities during the planning period is reflected uniformly in their respective plans. Disputes regarding the amount, timing, price, or other terms and conditions of such purchases and sales shall be fully explained in each utility's plan. If a utility files an interim plan as specified in rule 3603, the utility is not required to coordinate that filing with other utilities.

Credits

Amended Dec. 30, 2010; May 15, 2016.

Current through CR, Vol. 41, No. 13, July 10, 2018.

4 CCR 723-3:3607, 4 CO ADC 723-3:3607

End of Document

West's Colorado Administrative Code
Title 700. Department of Regulatory Agencies
723. Public Utilities Commission
4 CCR 723-3. Rules Regulating Electric Utilities (Refs & Annos)
Electric Resource Planning

4 CCR 723-3:3608
Alternatively cited as 4 CO ADC 723-3

723-3:3608. Transmission Resources.

Currentness

(a) The utility shall report its existing transmission capabilities, and future needs during the planning period, for facilities of 115 kilovolts and above, including associated substations and terminal facilities. The utility shall generally identify the location and extent of transfer capability limitations on its transmission network that may affect the future siting of resources.

(b) With respect to future needs, the utility shall submit a description of all transmission lines and facilities appearing in its most recent report filed with the Commission pursuant to § 40-2-126, C.R.S., that, as identified in that report, could reasonably be placed into service during the resource acquisition period.

(c) For each transmission line or facility identified in paragraph (b), the utility shall include the following information detailing assumptions to be used for resource planning and bid evaluation purposes:

(I) length and location;

(II) estimated in-service date;

(III) injection capacity;

(IV) estimated costs;

(V) terminal points; and

(VI) voltage and megawatt rating.

(d) In order to equitably compare possible resource alternatives, the utility shall consider the transmission costs required by, or imposed on the system by, and the transmission benefits provided by a particular resource as part of the bid evaluation criteria.

(e) The resource plan shall describe and shall estimate the cost of all new transmission facilities associated with any specific resources proposed for acquisition other than through a competitive acquisition process.

Credits

Amended Dec. 30, 2010; May 15, 2016.

Current through CR, Vol. 41, No. 13, July 10, 2018.

4 CCR 723-3:3608, 4 CO ADC 723-3:3608

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West's Colorado Administrative Code
Title 700. Department of Regulatory Agencies
723. Public Utilities Commission
4 CCR 723-3. Rules Regulating Electric Utilities (Refs & Annos)
Electric Resource Planning

4 CCR 723-3:3609
Alternatively cited as 4 CO ADC 723-3

723-3:3609. Planning Reserve Margins and Contingency Plans.

Currentness

(a) The utility shall provide a description of, and justification for, the means by which it assesses the desired level of reliability on its system throughout the planning period (e.g., probabilistic or deterministic reliability indices).

(b) The utility shall develop and justify planning reserve margins for the resource acquisition period for the base case, high, and low forecast scenarios established under rule 3606, to include risks associated with: the development of generation; losses of generation capacity purchase of power; losses of transmission capability; risks due to known or reasonably expected changes in environmental regulatory requirements; and, other risks. The utility shall develop planning reserve margins for its system over the planning period beyond the resource acquisition period for the base case forecast scenario. The utility shall also quantify the recommended or required reliability performance criteria for reserve groups and power pools to which the utility is a party.

(c) Since actual circumstances may differ from the most likely estimate of future resource needs, the utility shall develop contingency plans for the resource acquisition period. As a part of its plan, the utility shall provide, under seal, a description of its proposed contingency plans for the acquisition of additional resources if actual circumstances deviate from the most likely estimate of future resource needs developed pursuant to rule 3610; or, replacement resources in the event that resources are not developed in accordance with a Commission-approved plan under rule 3617. The utility will identify the estimated costs it will incur in developing the contingency plan for addressing the acquisition of these resources (e.g., purchasing equipment options, establishing sites, engineering). The Commission will consider approval of contingency plans only after the utility receives bids, as described in subparagraph 3618(b)(II). The provisions of paragraph 3617(d) shall not apply to the contingency plans unless explicitly ordered by the Commission.

Credits

Amended Dec. 30, 2010; Oct. 30, 2011; May 15, 2016.

Current through CR, Vol. 41, No. 13, July 10, 2018.

4 CCR 723-3:3609, 4 CO ADC 723-3:3609

End of Document

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Title 700. Department of Regulatory Agencies
723. Public Utilities Commission
4 CCR 723-3. Rules Regulating Electric Utilities (Refs & Annos)
Electric Resource Planning

4 CCR 723-3:3610
Alternatively cited as 4 CO ADC 723-3

723-3:3610. Assessment of Need for Additional Resources.

Currentness

(a) By comparing the electric energy and demand forecasts developed pursuant to rule 3606 with the existing level of resources developed pursuant to rule 3607, and planning reserve margins developed pursuant to rule 3609, the utility shall assess the need to acquire additional resources during the resource acquisition period.

(b) In assessing its need to acquire additional resources, the utility shall also:

(I) Determine the additional eligible energy resources, if any, the utility will need to acquire to comply with the Commission's RES rules.

(II) Take into account the demand-side resources it must acquire to meet the energy savings and peak demand reduction goals established under § 40-3.2-104, C.R.S. To that end, the Commission shall permit the utility to implement cost-effective demand-side resources to reduce the need for additional resources that would otherwise be met through a competitive acquisition process pursuant to rule 3611.

(c) The Commission may give consideration of the likelihood of new environmental regulations and the risk of higher future costs associated with the emission of greenhouse gases such as carbon dioxide when it considers utility proposals to acquire additional resources during the resource acquisition period.

Credits
Amended Dec. 30, 2010; May 15, 2016.

Current through CR, Vol. 41, No. 13, July 10, 2018.

4 CCR 723-3:3610, 4 CO ADC 723-3:3610

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Title 700. Department of Regulatory Agencies
723. Public Utilities Commission
4 CCR 723-3. Rules Regulating Electric Utilities (Refs & Annos)
Electric Resource Planning

4 CCR 723-3:3611
Alternatively cited as 4 CO ADC 723-3

723-3:3611. Utility Plan for Meeting the Resource Need.

Currentness

(a) It is the Commission's policy that a competitive acquisition process will normally be used to acquire new utility resources. The competitive bid process should afford all resources an opportunity to bid, and all new utility resources will be compared in order to determine a cost-effective resource plan (i.e., an all-source solicitation).

(b) Notwithstanding the Commission's preference for all-source bidding for the acquisition of all new utility resources under these rules, the utility may propose in its filing under rule 3603, an alternative plan for acquiring the resources to meet the need identified in rule 3610. The utility shall specify the portion of the resource need that it intends to meet through an all-source competitive acquisition process and the portion that it intends to meet through an alternative method of resource acquisition.

(c) If the utility proposes that a portion of the resource need be met through an alternative method of resource acquisition, the utility shall identify the specific resource(s) that it wishes to acquire and the reason the specific resource(s) should not be acquired through an all-source competitive acquisition process. In addition, the utility shall provide a cost-benefit analysis to demonstrate the reason(s) why the public interest would be served by acquiring the specific resource(s) through an alternative method of resource acquisition.

(d) Although the utility may propose a method for acquiring new utility resources other than all-source competitive bidding, as a prerequisite, the utility shall nonetheless include in its plan filed under rule 3603 the necessary bid policies, RFPs, and model contracts necessary to satisfy the resource need identified under rule 3610 exclusively through all-source competitive bidding.

(e) In the event that the utility proposes an alternative method of resource acquisition that involves the development of a new renewable energy resource or new supply-side resource that the utility shall own as a rate base investment, the utility shall file, simultaneously with its plan submitted under rule 3603, an application for a CPCN for such new resource. The Commission may consolidate, in accordance with the Commission's Rules of Practice and Procedure, the proceeding addressing that application for a CPCN with the resource planning proceeding. The utility shall provide a detailed estimate of the cost of the proposed facility to be constructed and information on alternatives studied, costs for those alternatives, and criteria used to rank or eliminate those alternatives.

(f) The utility may participate in a competitive resource acquisition process by proposing the development of a new utility resource that the utility shall own as a rate base investment. The utility shall provide sufficient cost information in support of its proposal such that the Commission can reasonably compare the utility's proposal to alternative bids. In the event a utility proposes a rate base investment, the utility shall also propose how it intends to compare the utility rate based proposal(s) with non-utility bids. The Commission may also address the regulatory treatment of such costs with respect to future recovery.

(g) Each utility shall propose a written bidding policy as part of its filing under rule 3603, including the assumptions, criteria, and models that will be used to solicit and evaluate bids in a fair and reasonable manner. The utility shall specify the competitive acquisition procedures that it intends to use to obtain resources under the utility's plan. The utility shall also propose, and other interested parties may provide input as part of the resource plan proceeding, criteria for evaluating the costs and benefits of resources such as the valuation of emissions and non-energy benefits.

(h) In the event that the utility proposes to acquire specific resources through an alternative method of resource acquisition that involves the development of a new renewable energy resource or new supply-side resource that the utility shall own as a rate base investment, the utility shall provide the Commission with the following best value employment metric information regarding each resource:

(I) the availability of training programs, including training through apprenticeship programs registered with the United States Department of Labor, Office of Apprenticeship and Training;

(II) the employment of Colorado workers as compared to importation of out-of-state workers;

(III) long-term career opportunities; and

(IV) industry-standard wages, health care, and pension benefits.

Credits

Amended Dec. 30, 2010; May 15, 2016.

Current through CR, Vol. 41, No. 13, July 10, 2018.

4 CCR 723-3:3611, 4 CO ADC 723-3:3611

End of Document

4 CCR 723-3:3612
Alternatively cited as 4 CO ADC 723-3

723-3:3612. Independent Evaluator.

Currentness

(a) Prior to the filing of the plan under rule 3603, the utility shall file for Commission approval the name of the independent evaluator who the utility, the Staff of the Commission, and the OCC jointly propose. Should the utility, the Commission Staff, and the OCC fail to reach agreement on an independent evaluator, the Commission shall refer the matter to an administrative law judge for resolution. In any event, the Commission shall approve an independent evaluator by written decision within 30 days of the filing of the plan under rule 3603.

(b) The utility shall pay for the services provided by the independent evaluator pursuant to a contract approved by the Commission. The terms of such contract shall prohibit the independent evaluator from assisting any entity making proposals to the utility for subsequent resource acquisitions for three years.

(c) The utility shall work cooperatively with the independent evaluator and shall provide the independent evaluator immediate and continuing access to all documents and data reviewed, used, or produced by the utility in the preparation of its plan and in its bid solicitation, evaluation, and selection processes. The utility shall make available the appropriate utility staff to meet with the independent evaluator to answer questions and, if necessary, discuss the prosecution of work. The utility shall provide to the independent evaluator, in a timely manner so as to facilitate the deadlines outlined in these rules, bid evaluation results and modeling runs so that the independent evaluator can verify these results and can investigate options that the utility did not consider. In the event that the independent evaluator notes a problem or a deficiency in the bid evaluation process, the independent evaluator should notify the utility.

(d) All parties in the resource plan proceeding other than the utility are restricted from initiating contacts with the independent evaluator. The independent evaluator may initiate contact with the utility and other parties. For all contacts with parties in the resource plan proceeding, including those with the utility, the independent evaluator shall maintain a log that briefly identifies the entities communicating with the independent evaluator, the date and duration of the communication, the means of communication, the topics discussed, and the materials exchanged, if any. Such log shall be posted weekly on the Commission's website for the duration of the independent evaluator's contract.

(e) In the event that the utility proposes a method for resource acquisition other than all-source competitive bidding, the Commission may retain the independent evaluator to assist the Commission in the rendering a decision on such alternative method for resource acquisition. The independent evaluator shall file a report with the Commission, prior to the evidentiary hearings, concerning its assessment of the costs and benefits that the utility has presented to the Commission to demonstrate the reason(s) why the public interest would be served by acquiring the specific resource(s) through that alternative method of resource acquisition. The independent evaluator shall also address in its report whether the utility's proposed competitive acquisition procedures and proposed bidding policy, including the assumptions, criteria and models, are sufficient to solicit and evaluate bids in a fair and reasonable manner.

(f) The independent evaluator shall generally serve as an advisor to the Commission and shall generally not be a party to the proceedings. As such, the independent evaluator shall not be subject to discovery and cross-examination at hearing. The Commission shall convene at least one procedural conference to establish a procedure related to questions to the independent evaluator from the utility and parties regarding the independent evaluator's filings in the proceeding.

Credits

Amended Dec. 30, 2010; May 15, 2016.

Current through CR, Vol. 41, No. 13, July 10, 2018.

4 CCR 723-3:3612, 4 CO ADC 723-3:3612

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Title 700. Department of Regulatory Agencies
723. Public Utilities Commission
4 CCR 723-3. Rules Regulating Electric Utilities (Refs & Annos)
Electric Resource Planning

4 CCR 723-3:3613
Alternatively cited as 4 CO ADC 723-3

723-3:3613. Bid Evaluation and Selection.

Currentness

(a) Upon the receipt of bids in its competitive acquisition process, the utility shall investigate whether each potential resource meets the requirements specified in the resource solicitation and shall perform an initial assessment of the bids. Within 45 days of the utility's receipt of bids, the utility shall provide notice in writing by e-mail to the owner or developer of each potential resource stating whether its bid is advanced to computer-based modeling to evaluate the cost or the ranking of the potential resource, and, if not advanced, the reasons why the utility will not further evaluate the bid using computer-based modeling. If, after the utility issues notice to an owner or developer that the potential resource was not advanced to computer-based modeling, the utility subsequently advances that potential resource to computer-based modeling, the utility shall provide notice in writing by e-mail to the owner or developer of that potential resource within three business days of the utility's decision to advance the potential resource to computer-based modeling.

(b) For bids advanced to computer-based modeling, the utility shall, contemporaneously with the notification in paragraph 3613(a), also provide to the owner or developer the modeling inputs and assumptions that reasonably relate to that potential resource or to the transmission of electricity from that facility to the utility. The utility shall provide such information so that modeling errors or omissions may be corrected before the competitive acquisition process is completed. Such information shall explain to the owner or developer how its facility will be represented in the computer-based modeling and what costs, in addition to the bid information, will be assumed with respect to the potential resource. In the event that this information contains confidential or highly confidential information, the owner or developer shall execute an appropriate nondisclosure agreement prior to receiving this information.

(c) Within seven calendar days after receiving the modeling inputs and assumptions from the utility pursuant to paragraph 3613(b), the owner or developer of a potential resource shall notify the utility in writing by electronic mail the specific details of any potential dispute regarding these modeling inputs and assumptions. The owner or developer shall attempt to resolve this dispute with the utility. However, if the owner or developer and utility cannot resolve the dispute within three calendar days, the utility shall immediately notify the Commission with a filing in the resource plan proceeding. If the owner or developer is not already a party to the proceeding, the owner or developer shall file a notice of intervention as of right pursuant to paragraph 1401(b) of the Commission's Rules of Practice and Procedure, within one business day of the utility's filing of its notice of dispute to the Commission, for the limited purpose of resolving the disputed modeling inputs and assumptions related to the potential resource. An Administrative Law Judge (ALJ) will expeditiously schedule a technical conference at which the utility and the owner or developer shall present their dispute for resolution. The ALJ will enter an interim order determining whether corrections to the modeling inputs and assumptions are necessary. If the ALJ determines that corrections to the modeling inputs and assumptions are necessary, the utility shall, within three business days of the issuance of the ALJ's interim decision, provide the corrected information to both the owner or developer and the independent evaluator. In its report submitted under paragraph 3613(d), the utility shall also confirm by performing additional modeling as necessary, that the potential resource is fairly and accurately represented.

(d) Within 120 days of the utility's receipt of bids in its competitive acquisition process, the utility shall file a report with the Commission describing the cost-effective resource plans that conform to the range of scenarios for assessing the costs and benefits from the potential acquisition of increasing amounts of renewable energy resources, demand-side resources, or Section 123 resources as specified in the Commission's decision approving or rejecting the utility plan developed under rule 3604. In the event that the utility's preferred cost-effective resource plan differs from the Commission-specified scenarios, the utility's report shall also set forth the utility's preferred plan. The utility's plan shall also provide the Commission with the best value employment metrics information provided by bidders under rule 3616 and by the utility pursuant to rule 3611.

(e) Within 30 days after the filing of the utility's 120-day report under paragraph 3613(d), the independent evaluator shall separately file a report that contains the independent evaluator's analysis of whether the utility conducted a fair bid solicitation and bid evaluation process, with any deficiencies specifically reported. The independent evaluator shall provide confidential versions of these reports to Commission staff and the OCC.

(f) Within 45 days after the filing of the utility's 120-day report under paragraph 3613(d), the parties in the resource plan proceeding may file comments on the utility's report and the independent evaluator's report.

(g) Within 60 days after the filing of the utility's 120-day report under paragraph 3613(d), the utility may file comments responding to the independent evaluator's report and the parties' comments.

(h) Within 90 days after the receipt of the utility's 120-day report under paragraph 3613(d), the Commission shall issue a written decision approving, conditioning, modifying, or rejecting the utility's preferred cost-effective resource plan, which decision shall establish the final cost-effective resource plan. The utility shall pursue the final cost-effective resource plan either with a due diligence review and contract negotiations, or with applications for CPCNs (other than those CPCNs provided in paragraph 3611(e)), as necessary. In rendering the decision on the final cost-effective resource plan, the Commission shall weigh the public interest benefits of competitively bid resources provided by other utilities and non-utilities as well as the public interest benefits of resources owned by the utility as rate base investments. In accordance with §§ 40-2-123, 40-2-124, 40-2-129, and 40-3.2-104, C.R.S, the Commission shall also consider renewable energy resources; resources that produce minimal emissions or minimal environmental impact; energy-efficient technologies; and resources that affect employment and the long-term economic viability of Colorado communities. The Commission shall further consider resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.

(i) The utility must complete the competitive acquisition process by executing contracts for potential resources within 18 months after the utility's receipt of bids in its competitive acquisition process. The utility may file a motion in the resource plan proceeding requesting to extend this deadline for good cause. The utility must execute final contracts for the potential resources prior to the completion of the competitive acquisition process to receive the presumption of prudence afforded by paragraph 3617(d).

(j) Upon completion of the competitive acquisition process pursuant to paragraph 3613(i), and consistent with the subsequent requirement for website posting of bids and utility proposals as required in paragraph 3613(k), protected information that was filed in the resource plan proceeding will be refiled as non-confidential or public information as specified in the Commission order described below. To satisfy this requirement the utility shall file a proposal that addresses the public release of all confidential and highly confidential information related to bids for potential resources and resources the utility proposed to build and own as a rate base investment. At a minimum the utility shall address its 120-day report in paragraph 3613(d), the independent evaluator's report in paragraph 3613(e), and all documents related to these reports filed by the utility, parties, or the independent evaluator. The utility shall file its proposal in the resource plan proceeding within 14 months after the receipt of bids in its competitive acquisition process. Parties will have 30 calendar days after the utility files its proposal to file responses. The utility then may reply to any responses filed within ten calendar days. The Commission shall issue an order specifying to the utility and other parties the documents that shall be refiled as public information.

(k) Upon completion of the competitive acquisition process under paragraph 3613(i), the utility shall post on its website the following information from all bids and utility proposals: bidder name; bid price and utility cost, stated in terms that allow reasonable comparison of the bids with utility proposals; generation technology type; size of facility; contract duration or expected useful life of facility for utility proposals; and whether the proposed power purchase contract includes an option for the utility to purchase the facility during or at the end of the contract term.

Credits
Amended Dec. 30, 2010; Oct. 30, 2011; May 15, 2016.

Current through CR, Vol. 41, No. 13, July 10, 2018.

4 CCR 723-3:3613, 4 CO ADC 723-3:3613

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Title 700. Department of Regulatory Agencies
723. Public Utilities Commission
4 CCR 723-3. Rules Regulating Electric Utilities (Refs & Annos)
Electric Resource Planning

4 CCR 723-3:3614
Alternatively cited as 4 CO ADC 723-3

723-3:3614. Confidential Information Regarding Electric Generation Facilities

Currentness

(a) In any proceeding related to a resource plan filed under rule 3603, an amendment to an approved plan filed under rule 3619, or pursuant to a request for information made under paragraph 3615(b), the provisions regarding confidential information set forth in rules 1100 through 1103 of the Commission's Rules of Practice and Procedure shall apply, in addition to this rule 3614.

(b) The utility shall provide information claimed to be highly confidential under subparagraph 1101(b) to a reasonable number of attorneys representing a party in the resource plan proceeding, provided that those attorneys file appropriate non-disclosure agreements containing the terms listed in subparagraph 3614(b)(I). The utility shall also provide information claimed to be highly confidential under subparagraph 1101(b) to a reasonable number of subject matter experts representing a party in the resource plan proceeding, provided that the attorney representing the party files the appropriate non-disclosure agreements for the subject matter experts containing the terms in subparagraph 3614(b)(II) and the subject matter experts' curriculum vitae.

(I) Attorney highly confidential nondisclosure agreement terms.

I [attorney name] state that I have read the protective provisions relating to confidential information contained in 4 Code of Colorado Regulations 723-1-1100 through 1103. With respect to all information claimed to be confidential and all information claimed to be highly confidential that is produced in, or arises in, the course of this proceeding in Proceeding No. [], I agree to be bound by the terms of the protective provisions contained in 4 Code of Colorado Regulations 723-1-1100. I hereby state that I will oversee the processes that any subject matter expert to whom I have authorized access to highly confidential information uses in order to assure that extraordinary confidentiality provisions are properly implemented and maintained. I hereby state that I will assure that extraordinary confidentiality provisions are properly implemented and maintained within my firm. I agree that all highly confidential information shall not be used or disclosed for purposes of business or competition, or for any other purpose other than for purposes of the proceeding in which the information is produced. I hereby state that I will not disclose or disseminate any highly confidential information in this Proceeding No. [] to any third party other than those specifically authorized to review such highly confidential information, including any third party who is or may become a bidder responding to future electric resource planning solicitations or otherwise relating to the acquisition of, contracting for, or retirement of electric generation facilities in Colorado.

(II) Subject Matter Expert highly confidential nondisclosure agreement terms.

I [subject matter expert's name] state that I have read the protective provisions relating to confidential information contained in 4 Code of Colorado Regulations 723-1-1100 through 1103. With respect to all information claimed to be confidential and all information claimed to be highly confidential that is produced in, or arises in the course of this proceeding in Proceeding No. [], I agree to be bound by the terms of the protective provisions contained in 4 Code of Colorado Regulations 723-1-1100. I hereby state that I will work with my attorney, [attorney name], to assure that extraordinary confidentiality provisions are properly implemented and maintained. I hereby state that I did not and will not develop or assist in the development of any power supply proposals associated with this proceeding. I agree that all highly confidential information shall not be used or disclosed for purposes of business or competition, or for any other purpose other than for purposes of the proceeding in which the information is produced. I hereby state that I will not disclose or disseminate any highly confidential information in this Proceeding No. [] to any third party other than those specifically authorized to review such highly confidential information, including any third party who is or may become a bidder responding to future electric resource planning solicitations or otherwise relating to the acquisition of, contracting for, or retirement of electric generation facilities in Colorado.

(c) Paragraph 3614(b) is only applicable to proceedings related to a resource plan filed pursuant to rule 3603, an amendment to an approved plan filed under rule 3619, or to a request for information made under paragraph 3615(b).

(d) In order to expedite access to confidential information at the beginning of the resource planning proceeding, an entity may file for intervention at any time during the 30-day notice period established in paragraph 1401(a) of the Commission's Rules of Practice and Procedure. If the entity requests an expedited decision on its motion it shall include in the title of its motion for intervention "REQUEST FOR EXPEDITED TREATMENT AND FOR SHORTENED RESPONSE TIME TO FIVE BUSINESS DAYS, PURSUANT TO RULE 3614(d)." The movant shall concurrently provide an electronic copy of the motion to the utility. Response time to any such motion is automatically shortened to five business days.

Credits

Amended Dec. 30, 2010; Oct. 30, 2011; May 15, 2016.

Current through CR, Vol. 41, No. 13, July 10, 2018.

4 CCR 723-3:3614, 4 CO ADC 723-3:3614

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Title 700. Department of Regulatory Agencies
723. Public Utilities Commission
4 CCR 723-3. Rules Regulating Electric Utilities (Refs & Annos)
Electric Resource Planning

4 CCR 723-3:3615
Alternatively cited as 4 CO ADC 723-3

723-3:3615. Exemptions and Exclusions.

Currentness

(a) The following resources need not be included in an approved resource plan prior to acquisition.

(I) Emergency maintenance or repairs made to utility-owned generation facilities.

(II) Capacity and/or energy from newly-constructed, utility-owned, supply-side resources with a nameplate rating of not more than 30 MW.

(III) Capacity and/or energy from the generation facilities of other utilities or from non-utility generators pursuant to agreements for not more than a two year term (including renewal terms) or for not more than 30 MW of capacity.

(IV) Improvements or modifications to existing utility generation facilities that change the production capability of the generation facility site in question, by not more than 30 MW, based on the utility's share of the total power generation at the facility site and that have an estimated cost of not more than $30 million.

(V) Interruptible service provided to the utility's electric customers.

(VI) Modification to, or amendment of, existing power purchase agreements provided the modification or amendment does not extend the agreement more than four years, does not add more than 30 MW of capacity to the utility's system, and is cost effective in comparison to other supply-side alternatives available to the utility.

(VII) Utility investments in emission control equipment at existing generation plants.

(VIII) Utility administered demand-side programs implemented in accordance with § 40-3.2-104, C.R.S.

(b) If the utility evaluates an existing or proposed electric generating facility offered in a competitive bidding process conducted outside of an approved resource plan, the utility shall provide the owner or developer of the electric generation facility in writing by e-mail the modeling inputs and assumptions that reasonably relate to the facility or to the transmission of electricity from that facility to the utility within 14 calendar days of the utility's decision to advance the potential resource to computer-based modeling.

Credits

Amended Dec. 30, 2010; Oct. 30, 2011; May 15, 2016.

Current through CR, Vol. 41, No. 13, July 10, 2018.

4 CCR 723-3:3615, 4 CO ADC 723-3:3615

End of Document

4 CCR 723-3:3616
Alternatively cited as 4 CO ADC 723-3

723-3:3616. Request(s) For Proposals.

Currentness

(a) Purpose of the request(s) for proposals. The proposed RFP(s) filed by the utility shall be designed to solicit competitive bids to acquire additional resources pursuant to rule 3611. To minimize bidder exceptions and to enhance bid comparability, the utility shall include in its proposed RFP(s) a model contract to match each type of resource need, including contracts for supply-side resources, renewable energy resources, or Section 123 resources as required by the approved resource plan.

(b) Contents of the request(s) for proposals. The proposed RFP(s) shall include the bid evaluation criteria the utility plans to use in ranking the bids received. The utility shall also include in its proposed RFP(s): details concerning its resource needs; reasonable estimates of transmission costs for resources located in different areas pursuant to rule 3608, including a detailed description of how the costs of future transmission will apply to bid resources; the extent and degree to which resources must be dispatchable, including the requirement, if any, that resources be able to operate under automatic dispatch control; the utility's proposed model contract(s) for the acquisition of resources; proposed contract term lengths; discount rate; general planning assumptions; and, any other information necessary to implement a fair and reasonable bidding program.

(c) Employment metrics. The utility shall request from bidders the following information relating to best value employment metrics for each bid resource:

(I) the availability of training programs, including training through apprenticeship programs registered with the United States Department of Labor, Office of Apprenticeship and Training;

(II) the employment of Colorado workers as compared to importation of out-of-state workers;

(III) long-term career opportunities; and

(IV) industry-standard wages, health care, and pension benefits.

(d) When issuing its RFP, the utility shall provide potential bidders with the Commission's order or orders specifying the form of nondisclosure agreement necessary to obtain access to confidential and highly confidential modeling inputs and assumptions provided by the utility pursuant to paragraph 3613(b). The utility shall also provide potential bidders with an explanation of the process by which disputes regarding inputs and assumptions to computer-based modeling will be addressed by the Commission pursuant to paragraph 3613(b).

(e) The utility shall require bidders to provide the contact name of the owner or developer designated to receive notice pursuant to paragraph 3613(a).

(f) The utility shall inform bidders that certain bid information submitted in response to the RFP will be made available to the public through the posting of certain bid information on the utility's website upon the completion of the competitive acquisition process pursuant to paragraph 3613(k).

Credits

Adopted Dec. 30, 2010. Amended Oct. 30, 2011; May 15, 2016.

Current through CR, Vol. 41, No. 13, July 10, 2018.

4 CCR 723-3:3616, 4 CO ADC 723-3:3616

End of Document

West's Colorado Administrative Code
Title 700. Department of Regulatory Agencies
723. Public Utilities Commission
4 CCR 723-3. Rules Regulating Electric Utilities (Refs & Annos)
Electric Resource Planning

4 CCR 723-3:3617
Alternatively cited as 4 CO ADC 723-3

723-3:3617. Commission Review and Approval of Resource Plans.

Currentness

(a) Review on the merits. The utility's plan, as developed pursuant to rule 3604, shall be filed as an application; shall meet the requirements of paragraphs 3002(b) and 3002(c); and shall be administered pursuant to the Commission's Rules Regulating Practice and Procedure. The Commission may hold a hearing for the purpose of reviewing, and rendering a decision regarding, the contents of the utility's filed resource plan.

(b) Basis for Commission decision. Based upon the evidence of record, the Commission shall issue a written decision approving, disapproving, or ordering modifications, in whole or in part, to the utility's plan filed in accordance with rule 3604. If the Commission declines to approve a plan, either in whole or in part, the utility shall make changes to the plan in response to the Commission's decision. Within 60 days of the Commission's rejection of a plan, the utility shall file an amended plan with the Commission and shall provide the amended plan to all parties who participated in the application proceeding concerning the utility's plan. All such parties may participate in any hearings regarding the amended plan.

(c) Contents of the Commission decision. The Commission decision approving or denying the plan shall address the contents of the utility's plan filed in accordance with rule 3604. If the record contains sufficient evidence, the Commission shall specifically approve or modify: the utility's assessment of need for additional resources in the resource acquisition period; the utility's plans for acquiring additional resources through an all-source competitive acquisition process or through an alternative acquisition process; components of the utility's proposed RFP, such as the model contracts and the proposed evaluation criteria; and, the alternate scenarios for assessing the costs and benefits from the potential acquisition of increasing amounts of renewable energy resources, demand-side resources, or Section 123 resources. A Commission decision pursuant to paragraph 3613(h) shall become part of the decision approving or modifying a utility's plan developed under rule 3604.

(d) Effect of the Commission decision. A Commission decision specifically approving the components of a utility's plan creates a presumption that utility actions consistent with that approval are prudent.

(I) In a proceeding concerning the utility's request to recover the investments or expenses associated with new resources.

(A) The utility must present prima facie evidence that its actions were consistent with Commission decisions specifically approving or modifying components of the plan.

(B) To support a Commission decision to disallow investments or expenses associated with new resources on the grounds that the utility's actions were not consistent with a Commission approved plan, an intervenor must present evidence to overcome the utility's prima facie evidence that its actions were consistent with Commission decisions approving or modifying components of the plan. Alternatively, an intervenor may present evidence that, due to changed circumstances timely known to the utility or that should have been known to a prudent person, the utility's actions were not proper.

(II) In a proceeding concerning the utility's request for a CPCN to meet customer need specifically approved by the Commission in its decision on the final cost-effective resource plan, the Commission shall take administrative notice of its decision on the plan. Any party challenging the Commission's decision regarding need for additional resources has the burden of proving that, due to a change in circumstances, the Commission's decision on need is no longer valid.

Credits

Adopted Dec. 30, 2010. Amended Oct. 30, 2011; May 15, 2016.

Current through CR, Vol. 41, No. 13, July 10, 2018.

4 CCR 723-3:3617, 4 CO ADC 723-3:3617

End of Document

West's Colorado Administrative Code
Title 700. Department of Regulatory Agencies
723. Public Utilities Commission
4 CCR 723-3. Rules Regulating Electric Utilities (Refs & Annos)
Electric Resource Planning

4 CCR 723-3:3618
Alternatively cited as 4 CO ADC 723-3

723-3:3618. Reports.

Currentness

(a) Annual progress reports. The utility shall file with the Commission, and shall provide to all parties to the most recent resource planning proceeding, annual progress reports after submission of its plan application. The annual progress reports will inform the Commission of the utility's efforts under the approved plan and the emerging resource needs and potential utility proposals that may be part of the utility's next electric resource plan filing. Annual progress reports shall contain the following, for a running ten-year period beginning at the report date:

(I) an updated annual electric demand and energy forecast developed pursuant to rule 3606;

(II) an updated evaluation of existing resources developed pursuant to rule 3607;

(III) an updated evaluation of planning reserve margins and contingency plans developed pursuant to rule 3609;

(IV) an updated assessment of need for additional resources developed pursuant to rule 3610;

(V) an updated report of the utility's plan to meet the resource need developed pursuant to rule 3611 and the resources the utility has acquired to date in implementation of the plan; and

(VI) in addition to the items required in subparagraphs(a)(I) through (a)(V), a cooperative electric generation and transmission association shall include in its annual report a full explanation of how its future resource acquisition plans will give fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions for electric utilities, bearing in mind the beneficial contributions such technologies make to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.

(b) Reports of the competitive acquisition process. The utility shall provide reports to the Commission concerning the progress and results of the competitive acquisition of resources. The following reports shall be filed:

(I) Within 30 days after bids are received in response to the RFP(s), the utility shall report: the identity of the bidders and the number of bids received; the quantity of MW offered by bidders; a breakdown of the number of bids and MW received by resource type; and, a description of the prices of the resources offered.

(II) If, upon examination of the bids, the utility determines that the proposed resources may not meet the utility's expected resource needs, the utility shall file, within 30 days after bids are received, an application for approval of a contingency plan. The application shall include the information required by paragraphs 3002(b) and 3002(c), the justification for need of the contingency plan, the proposed action by the utility, the expected costs, and the expected timeframe for implementation.

Credits

Adopted Dec. 30, 2010. Amended Oct. 30, 2011; May 15, 2016.

Current through CR, Vol. 41, No. 13, July 10, 2018.

4 CCR 723-3:3618, 4 CO ADC 723-3:3618

End of Document

West's Colorado Administrative Code
Title 700. Department of Regulatory Agencies
723. Public Utilities Commission
4 CCR 723-3. Rules Regulating Electric Utilities (Refs & Annos)
Electric Resource Planning

4 CCR 723-3:3619

723-3:3619. Amendment of an Approved Plan.

Currentness

The utility may file, at any time, an application to amend the contents of a plan approved pursuant to rule 3617. Such an application shall meet the requirements of paragraphs 3002(b) and 3002(c), shall identify each proposed amendment, shall state the reason for each proposed amendment, and shall be administered pursuant to the Commission's Rules Regulating Practice and Procedure.

Credits

Adopted Oct. 30, 2011. Amended May 15, 2016.

Current through CR, Vol. 41, No. 13, July 10, 2018.

4 CCR 723-3:3619, 4 CO ADC 723-3:3619

End of Document

Exhibit 7

Service date: May 7, 2018

STATE OF WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION
1300 S. Evergreen Park Dr. S.W., P.O. Box 47250 • Olympia, Washington 98504-7250
(360) 664-1160 • www.utc.wa.gov

May 07, 2018

Mr. John Piliaris
Director of State Regulatory Affairs
Puget Sound Energy
10608 Northeast 4th Street
Bellevue, Washington 98009-9734

Re: Puget Sound Energy's 2017 Electric and Natural Gas Integrated Resource Plan Docket UE-160918 & UG-160919

Dear Mr. Piliaris:

The Washington Utilities and Transportation Commission (Commission) has reviewed the 2017 Electric and Natural Gas Integrated Resource Plan (IRP) filed by Puget Sound Energy (PSE or Company) on November 14, 2017, and finds that it meets the requirements of Revised Code of Washington (RCW) 19.280.030 and Washington Administrative Code (WAC) 480-100-238.

By acknowledging compliance with statute and rule, the Commission does not signal pre-approval for ratemaking purposes of any course of action identified in the IRP. The Commission will review the prudence of the Company's actions at the time of any future request to recover costs of resources in customer rates. The Commission will reach a prudence determination after giving due weight to the information, analyses, and strategies contained in the Company's IRP along with other relevant evidence.

Because an IRP cannot pinpoint precisely the future actions that will minimize a utility's costs and risks, we expect that the Company will regularly update the assumptions that underlie the analysis within the IRP and adjust its investment strategies accordingly.

The attached document provides specific comments regarding the 2017 IRP and expectations for the 2019 IRP. Please note that with regard to Section III (g), Commissioner Balasbas does not agree with the Commission majority and has written a separate statement.

Sincerely,

MARK L. JOHNSON
Executive Director and Secretary

Attachment - UTC Comments on Puget Sound Energy's 2017 IRP

Acknowledgment Letter Attachment
Puget Sound Energy's 2017 Electric and Natural Gas Integrated Resource Plan
Dockets UE-160918 and UG-160919

I. Introduction

RCW 19.280.030, WAC 480-100-238, and WAC 480-90-238 direct investor-owned electric and natural gas companies (IOUs) to develop an integrated resource plan (IRP or the Plan) every two years. The IRP must identify "the mix of energy supply resources and conservation that will meet current and future needs at the lowest reasonable cost to the utilities and its ratepayers."[1] The IRP touches every aspect of a company's operations and provides essential public participation opportunities for stakeholders to assist in the development of an effective plan. In preparing an IRP, utilities are required to consider changes and trends in energy markets, resource costs, cost of risks associated with greenhouse gas emissions, state and federal regulatory requirements, and other shifts in the policy and market landscape.[2] The statute and the Washington Utilities and Transportation Commission's (Commission) rules require that IOUs conduct a comprehensive analysis of the costs, benefits, and risks of various approaches to meeting future resource needs using commercially available information. The intent is for each regulated utility to develop a strategic approach that fits its unique situation, while minimizing risks and costs for the company and its ratepayers.

The development of Puget Sound Energy's (PSE or the Company) IRP and involvement of stakeholders and Commission staff (Staff) has been the most extensive such effort in memory. Over the course of the IRP, PSE held 16 meetings with stakeholders and the public. The Company also improved its stakeholder process by hiring an employee to manage its external communications with the advisory group. The Commission acknowledges and appreciates PSE's efforts in this IRP. We also acknowledge the stakeholders and members of the public who participated in the IRP meetings, submitted verbal and written comments, and attended the Commission's recessed open meeting. Their involvement improved the Company's final IRP and the Commission's process.

The Commission determines that Puget Sound Energy's 2017 Electric and Natural Gas IRP complies with the statute and rules governing IRPs and recommends the Company address several areas for improvement in developing its next IRP. In the following sections, we provide comments on the 2017 IRP and identify specific areas for improvement for the 2019 IRP.

II. Summary of 2017 Electric and Gas Integrated Resource Plan

a. Electric Portfolio Summary and Action Plan

[1] RCW 19.280.(9).
[2] RCW 19.280.020(11); WAC 480-100-238(2)(b).

As with the last several of its IRPs, PSE's 20-year load projections in its 2017 IRP are lower than the preceding IRP. After PSE applies demand-side resources, annual average energy demand is expected to increase at 0.4 percent annually, and peak growth at 0.6 percent per year to 5,664 MW in 2037.[3]

Figure 1: PSE 20-year electric load growth projection 2018-2037

	Annual Energy Growth	**Annual Peak Growth**
Before DSR	1.7%	1.6%
After DSR	0.4%	0.6%

Annual average energy growth is negative (-0.3 percent) for the first 10 years of the IRP, but increases to 1.1 percent per year from 2027 to 2037. Peak demand growth is also flat for the first 10 years, but ticks up to 1.1 percent in the second half of the plan.[4] As will be discussed later, the substantial increase in the latter half of the Plan is due to PSE's assumption that there is no cost-effective retrofit conservation of existing buildings beyond 10 years.

The rate of change of residential electric use per customer is negative after the application of demand-side resources (DSR), therefore, growth is expected to be driven by the increased number of customers.[5] Consistent with economic and population growth trends in the state, the Plan emphasizes that its electric growth is unevenly distributed, with nearly all of the customer growth occurring in its King County service territory.[6]

Figure 1: PSE 20-year electric load growth projection 2018-2037

	Annual Energy Growth	**Annual Peak Growth**
Before DSR	1.7%	1.6%
After DSR	0.4%	0.6%

PSE's Integrated Resource Planning Solution – its lowest-reasonable-cost portfolio – continues to rely heavily on energy efficiency and market purchases throughout the planning period.[7] Although load growth is slowing, PSE expects significant capacity needs during the 20-year period due, in part, to coal plant retirements and expiring long-term purchase power agreements (PPAs).[8]

[3] Page 5-7 of PSE's 2017 IRP.
[4] Page 5-7 of PSE's 2017 IRP.
[5] Page 5-3 of PSE's 2017 IRP.
[6] Page 5-31 of PSE's 2017 IRP.
[7] The Company does not build an 'Expected Case' or 'Preferred Portfolio' as does Avista and Pacific Power. The Company determines an 'Integrated Resource Planning Solution' as the Company's lowest reasonable cost portfolio from which it builds its Action Plan.
[8] Page 1-12 of PSE's 2017 IRP. The following are identified to be removed from the resource stack: 300 MW from Colstrip Units 1&2 in 2022, 380 MW from Centralia in 2025, 481 MW from Chelan PUD in 2031, and 370 MW from Colstrip Units 3&4 in 2035.

To meet its capacity need over the 20-year horizon, PSE plans to increase its reliance on the Mid-Columbia market hub (Mid-C) for market purchases, by redirecting another 188 MW of available transmission from its wind facilities in southeast Washington to the Mid-C.[9] With this improvement in its ability to use its existing cross-Cascade transmission capacity, the Company will have over 1600 MW of transmission available on which to schedule Mid-C market purchases for meeting peak energy needs.

The Base scenario forecasts that the Company will need 215 MW of additional peaking capacity by 2023.[10] To meet the requirements of the state Energy Independence Act, PSE expects it will need approximately 720,000 qualifying renewable energy credits by 2023, the equivalent of a 227 MW wind project or 266 MW of eastern Washington solar.[11] The Company also intends to acquire 741 MW of conservation over the 20-year period, 148 MW of demand response, and 75 MW of energy storage.

PSE's 2017 Electric Action Plan comprises the following:[12]

- Acquire 374 MW of energy efficiency by 2023.
- Issue a new demand response request for proposal (RFP) based on recent work on the prudence criteria and cost recovery mechanism.
- Install a small-scale flow battery to gain operational experience.
- Issue an all-source RFP in the first quarter of 2018 to meet its renewable and capacity need in 2022.
- Develop options to mitigate risk of relying on the market to meet energy and capacity needs.
- Continue to participate in the Energy Imbalance Market.
- Examine regional transmission needs in the 2019 IRP including re-purposing Colstrip transmission rights.

b. Natural Gas Portfolio Summary and Action Plan

The IRP identifies a natural gas shortfall beginning in the winter of 2018, and then again each year beginning in the winter of 2023.[13] To meet the short-term need in 2018, the IRP states that PSE will contract for short-term firm pipeline capacity to Sumas. Beginning in 2022, the Company will expand the Swarr propane facility.

[9] PSE has additional transmission capacity from its wind facilities in southeast Washington because the facilities have not achieved the capacity factor PSE projected at the time the facilities were built. PSE has had to reduce its projected capacity factor twice since the facilities were placed in service.

[10] Page 1-12 of PSE's 2017 IRP.

[11] Page 1-15 of PSE's 2017 IRP. PSE could also use unbundled renewable energy credits to meet some or all of its compliance obligations.

[12] Pages 1-7 – 1-10 of PSE's 2017 IRP.

[13] PSE expects the Tacoma Liquified Natural Gas (LNG) project to be completed by the 2019/2020 heating season providing capacity relief until 2023/2024.

To solve for the gas capacity shortfall, PSE modeled energy efficiency and various supply-side resources. PSE intends to acquire 14 million dekatherms per day (MDth/day) by winter of 2021 and 65 MDth/day by 2033. The IRP finds less conservation than the 2015 IRP due to lower demand forecasts, updated measure savings, and lower natural gas prices.[14] However, PSE increased its estimated achievability from 75 percent to 85 percent relative to the previous IRP. The Plan also finds the Swarr propane facility to be a least-cost resource in most scenarios because upgrading the facility is fully within PSE's ability to control and the Company has the flexibility to "fine-tune" the timing of this resource.[15] This expansion would add 30 MDth/day of capacity.

The Plan states that the Tacoma LNG facility is needed by 2021 in the high-growth scenarios, but under the Base Scenario, it is not needed until 2029. The project would add 16 MDth/day of capacity.

Finally, the Plan assumes the expansion of the Westcoast Pipeline from the Station 2 hub in Canada to the Sumas hub and the Northwest Pipeline from Sumas to PSE's service territory by 2029. The project would initially provide 61 MDth/day of capacity, increasing to 140 MDth/day by winter 2037.[16] PSE notes that this project does not require participation from any other party, unlike other pipeline alternatives.[17]

PSE's 2017 Natural Gas Action Plan includes:[18]

- Acquire 14 MDth per day of energy efficiency by 2022.
- Complete the PSE LNG peaking project by the 2019/2020 heating season.
- Maintain the ability to upgrade the Swarr propane-air injection system for the 2024/2025 heating season.

III. Comments and Modeling Improvements

PSE's electric and natural gas analysis of its resource needs over the 20-year planning horizon is generally comprehensive, and the Commission is satisfied with the scope of analysis and overall presentation.

An IRP is an iterative process in which the Company regularly updates its assumptions and responds to the external environment. The key inputs in an IRP such as load growth rate forecasts, natural gas prices, and environmental regulation risks, change from year to year. As such, out of each IRP the Commission asks the Company to consider new modeling scenarios

[14] Page 7-37 of PSE's 2017 IRP.
[15] Page 2-26 of PSE's 2017 IRP. Swarr is an extreme peaking facility that mixes propane and air in a ratio that approximates the heat content of pipeline gas.
[16] This option only evaluated an expansion of Northwest Pipeline from Sumas to PSE's service territory; it did not model an expansion on Northwest Pipeline's east-west route through the Columbia Gorge.
[17] Page 7-37 of PSE's 2017 IRP.
[18] Page 1-11 of PSE's 2017 IRP.

and sensitivities, or other improvements in its next Plan. The following section explains the topics and issues on which the Commission would like further analysis.

a. Continued Reliance on Market Purchases to Meet Peak Needs

PSE relies on nearly 1,600 MW of wholesale market purchases to meet its energy and peak capacity needs, and expects to increase that reliance in the 20-year plan.[19] Describing the risk of relying on wholesale market purchases, PSE writes that,

> While uncertainties remain, there are also reasons for increased confidence. So, while there is still some level of risk to PSE in relying on wholesale market purchases in order to meet resource need, this risk appears to be significantly reduced from the level presented in the 2015 IRP…[20]

PSE based its assessment on the updated long-term regional resource adequacy (RA) studies performed by the Northwest Power and Conservation Council (Council), the Pacific Northwest Utilities Conference Committee, and the Bonneville Power Administration conducted since the completion of the 2015 IRP. PSE is also more comfortable with its RA position than it was in the 2015 IRP because it shifted back to a 5 percent loss of load probability (LOLP) metric for capacity planning, as opposed to the Value of Lost Load approach in the previous plan.[21]

However, we are concerned that the Company's view of the reduction in risk of relying on the market for capacity at its current level may be unrealistic as part of a utility's preferred portfolio. Beginning after 2000, independent power producers added considerable generation capacity in the Northwest region that went unsubscribed and subsequently became surplus in the region. This provided utilities a temporary opportunity to pursue a least-cost strategy of reliance on the market to complete their capacity needs. The market capacity surplus is now dwindling and it does not appear that independent developers are stepping forward again to build without firm contracts. Both PSE and the Council are increasingly uncertain that there is sufficient RA in the next five years, and therefore a capacity-short position is an increasing possibility.

In demonstrating prudent utility action, PSE is responsible for considering market-volatility risks as a result of not acquiring fixed-cost generation assets or demand-side resources for meeting customer demand. PSE's 20-year resource plan does not necessarily need to show a path to closing out PSE's reliance on the market for its capacity resource needs.[22] As explained in the next section, the Company's continued improvements in its RA analysis is impressive. However, in all three of the RA studies described in the IRP, the direction of RA beyond 2021 is clear: capacity markets are likely to fall short of meeting the RA standards. Unfortunately, the

[19] Appendix G of PSE's 2017 IRP.
[20] Appendix G, p. G-4 of PSE's 2017 IRP.
[21] Page G-4 of PSE's 2017 IRP. Five percent LOLP is the planning standard used by the Northwest Power and Conservation Council.
[22] Pages 6-12, 1-9, and 2-6 of PSE's 2017 IRP.

IRP does not expressly model or address market prices that can result from a tight capacity market.[23]

Such analysis is arguably very difficult to perform in an IRP setting, but both theory and historical experience suggest that demand will be inelastic, leading to very high costs for purchasing capacity from a tight market. Without a firm analysis that can establish a reliable boundary for those potential costs, the absence of a plan for eliminating reliance on market purchases over the 20-year plan carries excessive risk. Therefore, PSE should pursue and model IRP alternatives to its historically heavy reliance on market resources to satisfy medium-term and long-term capacity needs.

b. Resource Adequacy (RA)

PSE re-examined its 2015 IRP RA analysis, moving back to the Council's 5 percent LOLP. PSE also examined two other RA metrics, the Expected Unserved Energy (EUE) resource adequacy metric, which is a quantitative measure of the magnitude of load curtailments, and the Loss of Load Expectation (LOLE) metric, also called the Loss of Load Hours (LOLH), which provides information about the duration of the curtailment events.

Each of these metrics provide unique heuristic measures of the failure to serve load. The Commission agrees with PSE's pursuit of the use of EUE and LOLE along with its use of LOLP. Though PSE and others in the industry will need to address how to balance the interpretations of the three unique measurements, the Commission recognizes PSE's leading effort to employ EUE and LOLE.

c. Colstrip Generating Station

In its 2011 Acknowledgment Letter, the Commission requested that PSE conduct a broad examination of the cost of continuing the operation of the Colstrip Generating Station over the 20-year planning horizon, including a range of anticipated costs associated with federal Environmental Protection Agency (EPA) regulations on coal-fired generation.[24] It also asked that PSE model a scenario without Colstrip that includes results showing how PSE would choose to meet its load obligations without Colstrip in its portfolio and estimates of the impact on Net Present Value (cost) of its portfolio and rates.

In its 2013 IRP, PSE ran four cases on Colstrip's environmental compliance costs.[25] PSE identified as the most likely scenario Case 2, which assumes Units 1 & 2 must comply with EPA Best Available Retrofit Technology requirements of EPA's Regional Haze Federal Implementation Plan. Under Case 2 conditions, PSE determined that all four Colstrip units

[23] The IRP uses an expansion model that adds capacity resources to prevent capacity shortages from thwarting price formation in the model.
[24] PSE's 2011 Electric and Gas Integrated Resource Plan, Dockets UE-100961 & UG-100960, Attachment: Utilities and Transportation Commission Comments.
[25] See PSE 2013 Integrated Resource Plan, Dockets UE-120767 and UG-120768, pp. 5-41 – 5-55.

would continue to run in six of its 10 scenarios including in its expected Base Case, and Units 3 & 4 continue to run in two of the remaining four.[26] In the Commission's 2013 Acknowledgment Letter, the Commission was unable to conclude that PSE's analysis demonstrated that the continued operation of Colstrip Units 1 & 2 should or should not be a component of the Selected Resource Plan.[27] Since the 2013 IRP, PSE has committed to closing Units 1 & 2 by July, 2022.[28]

In its 2017 IRP, PSE found that the continued operation of Units 3 & 4 is highly dependent upon future environmental regulations, and that a carbon policy would add to the dispatch costs of the units could make the units uneconomical. PSE conducted three sensitivities on how different retirement dates for the four units could affect decisions on what types of resources to replace Colstrip.[29]

The Company's Colstrip sensitivities are a useful exercise to inform itself, the Commission and the public of what types of resources could replace Colstrip Units 1-4 when they close, and at what cost. However, they do not address the economics of continuing to run Units 1 & 2 until July, 2022, and Units 3 & 4 indefinitely.

PSE's IRP does not identify the costs of outstanding liabilities for remediation responsibilities associated with the closure of Colstrip Units 1-4, or how those liabilities might grow with continued operation of the units. Such open-ended liabilities should be accounted for in assessing the monetary risk of operating the units within PSE's portfolio. In its 2017 general rate case, PSE agreed to a settlement to set the depreciation schedule for Units 3 & 4 to December 31, 2027, but did not commit to closing the units at that time.[30] In that case, PSE testified that "$95 million in hydro-related Treasury Grants addresses nearly all of the estimated decommissioning and remediation costs for Colstrip Units 1 & 2," and "remaining PTCs are available to fund additional decommissioning and remediation, if needed, after the $95 million in Treasury Grants has been used."[31] The Company did not estimate decommissioning and remediation costs for Units 3 & 4.

We are deeply concerned with the direct costs of continued operation of Colstrip Units 1-4 and the magnitude of economic risk of continued investment in those units. Nowhere in this IRP does PSE explicitly express or discuss risks imposed on the utility and its ratepayers, including costs of risks associated with Colstrip's fuel source, projected capital investments, and ongoing operational expenses, much less decommissioning and remediation cost assumptions. In the 2019 IRP, the Commission expects PSE to answer the following questions pertaining to Colstrip:

1. Regarding fuel source cost and risk:
    a. How dependent is Colstrip on a single-source mine for its fuel?

[26] See PSE 2013 Integrated Resource Plan, Dockets UE-120767 and UG-120768, page 5-46.
[27] PSE's 2013 Electric and Gas Integrated Resource Plan, Dockets UE-120767 and UG-120768, Attachment B: Utilities and Transportation Commission Comments.
[28] Page 1-5 of PSE's 2017 IRP.
[29] Page 4-5 of PSE's 2017 IRP. Sensitivity 1 retires Units 1 & 2 in 2018, Sensitivity 2 retires Units 3 & 4 in 2025, and Sensitivity 3 retires Units 3 & 4 in 2030.
[30] Dockets UE-170033 and UG-170034, Exh. PSE-1JT at 7:6-12.
[31] Dockets UE-170033 and UG-170034, Exh. PSE-1JT at 5:13-6:3.

  b. How well understood is the supply of coal from the Colstrip mine?
     i. What are the financial risks of the type of mining used to extract the existing coal?
     ii. As the need for fuel for Colstrip declines, how does the cost per unit of coal from the Colstrip mine increase?
     iii. What are the counter-party risks of mine operation?
     iv. What risks to coal supply and coal cost does the Joint Colstrip ownership agreement impose? How will PSE manage them?
  c. How does the fuel supply risk from Colstrip compare to that of natural gas?
2. Does PSE have an assessment of the cost related to the counter-party risk of Riverstone ceasing operation of its share of Colstrip Unit 3?[32] If not, why not?
3. Does PSE have an assessment of the cost of the counter-party risk of Riverstone being financially unable or otherwise failing to pay its share of decommissioning and remediation costs for Unit 3?
4. How are the economics of Colstrip Units 1 & 2 and Units 3 & 4 affected if natural gas prices continue to remain relatively flat?
5. What are PSE's best estimates of remediation and decommissioning costs associated with Colstrip Units 3 & 4?
6. Has PSE quantified capacity replacement costs for Colstrip Units 3 & 4 that it could use as a basis of seeking replacement capacity as an alternative to any large capital investments it faces at Colstrip?
7. What is the risk of the failure of a large cost component of Colstrip Units 3 & 4 (such as: the heat exchangers, steam turbine or drive shafts) over PSE's expected 20-year life of the plant?

The economic viability of Colstrip is dependent on the outcome of numerous future events. To properly capture the expected cost of Colstrip over the 20-year horizon of an IRP, the probability of each event needs to be assessed and the cost weighted by its probability of occurrence. This comprehensive approach produces a probability distribution for the set of possible total cost outcomes of the operation of Colstrip over the planning horizon. The Commission recognizes that the approaches to this analysis may vary; however, regardless of the approach used, each utility's resource plan must comprehensively assess all categories of cost and risk, particularly for complex resources like Colstrip Units 3 & 4 that are included in the Plan and future plans. In its next IRP, PSE should assess all categories of operational costs for Colstrip Units 1-4 and explicitly identify the range of possible costs in each category over the expected life of the units. PSE should also identify whether the costs are known or if they are open-ended. If costs are not known and measurable, the risk that such unknowns add to the utility portfolio should be identified by modeling a range of possible costs or other suitable means. As appropriate, the probability needs to be assessed and the cost weighted by its probability of occurrence. The Company's 2019 Plan should clearly and transparently identify cost data and discuss in detail the relationship between the range of these input assumptions, portfolio modeling logic, and the output of the modeling, as well as how the Company used such analysis to choose its Integrated Resource Planning Solution.

[32] Riverstone purchased the assets of Talen Energy.

d. Resource Cost Assumptions

The Company's assumptions on the cost and values of new generation resources was a major point of debate throughout the IRP process. PSE contracted Black and Veatch to provide price estimates for generic thermal resources, which showed frame peaking plants dropping 30 percent in price from the 2015 IRP.[33] PSE's own cost analysis for renewable energy generation found relatively modest price decreases. After some members of the advisory group put forth their own cost estimates using non-PSE data, and significant debate within the advisory group, PSE contracted for additional analysis for the cost of generic renewable resources from the consulting firm DNV-GL.[34] PSE took the right step in seeking additional, third-party analysis. However, some stakeholders continued to disagree with PSE's resource assumptions.

Writing on behalf of Sierra Club, Synapse Energy argued that PSE continues to overstate the costs associated with renewable resources and unnecessarily constrains the cumulative development of renewable resources in its portfolio over the planning horizon.[35] Renewable Northwest argued that PSE's assumption that utility scale solar has a capacity contribution of zero percent ignores its contribution to resource adequacy.[36] Multiple stakeholders raised concerns that PSE does not clearly define either the cost or capacity contribution estimates, or continue to express concerns over what they consider to be a lack of transparency about which cost components are included in the construction of the cost of each resource type.[37]

We recognize the Company and the stakeholders for working through this issue to the betterment of the IRP. Although not all members of the stakeholder group are satisfied with the Company's assumptions in the Plan, this type of Advisory Group discussion is necessary. Especially in IRPs that occur long after the Company has received actual cost bids in an all-source RFP, it is important for the Company to ensure it is using the best, commercially available resource costs. Fortunately, PSE will have the all-in cost estimates for many types of generators as a result of its 2018 all-sources RFP. However, if the Company relies on third-parties to provide the latest commercially available information, it is important for the Company to accurately assign generic costs, such as owners cost, to the specific technology as applicable. We also require that the Company present resource costs in a consistent reporting format, and continue to reassess its assumptions for each type of generation resource, including projected costs and year-round and peak capacity valuations.

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[33] Page 4-32 of PSE's 2017 IRP. Frame peaker NG-only 1x0 capital cost is $639/kW. In the 2015 IRP a frame peaker with oil was $879/kW.
[34] DNV-GL also provided Portland General Electric with its generic renewable resource costs in its latest IRP.
[35] Synapse Energy Economics Inc. Comments on Puget Sound Energy's 2017 Integrated Resource Plan, pp. 1-2, 6-11.
[36] Comments of Renewable Northwest, p. 5.
[37] Comments of Orion Renewable Energy Group LLC, Comments from Invenergy LLC, Comments of Renewable Northwest, Comments from the Northwest Energy Coalition, Comments from Synapse Energy Economics Inc. prepared for Sierra Club, and Comments from Climate Solutions.

e. Energize Eastside

At the request of stakeholders, PSE provided studies in support of the reliability need it identified and potential alternative solutions to the Energize Eastside Project.[38] However, we heard from Staff and some stakeholders that PSE would not discuss these studies in the advisory group, and therefore left unresolved some basic questions about the studies' assumptions, methodologies, and conclusions. For example, the Plan does not include a narrative regarding:

- The effect of the power flows due to entitlement returns on the need for the Energize Eastside Project.[39]
- The reason for, and effect on the need for the Energize Eastside Project, of modeling zero output from five of PSE's Westside thermal generation facilities.
- PSE's choice not to provide modeling data to stakeholders with Critical Energy Infrastructure Information clearance from FERC.
- Resolution of the effect of lower load assumptions on the need for Energize Eastside Project.

The IRP process is specifically structured to allow public discussion and inquiry, including a thorough examination of the analysis supporting a conclusion of need. This is an area in which we would like to see more engagement from the Company.

In describing the status of the Energize Eastside Project with respect to its 2017 IRP, PSE states, "the needs assessment and solution identification phases of this project have been completed. Currently, the project is in the route selection and permitting phases."[40] WAC 480-100-238(3)(d) requires an integrated resource plan to include "[a]n assessment of transmission system capability and reliability, to the extent such information can be provided consistent with applicable laws." The Company has an obligation to bring major transmission investments into the IRP for examination. The Company complied with the letter of the law in Chapter 8 where it provided a history of its Needs Assessment Reports. However, the Plan did not answer many questions that are needed for determining if the Company's conclusions are justified. For instance, it is still not clear if a joint utility analysis of all available transmission and potential interconnections in the Puget Sound region might solve the Energize Eastside reliability issues. Whether PSE has engaged in such analysis or discussions remains unclear and would have been better answered in the IRP.

f. Load Growth and the Effects of Conservation

PSE's forecasted increase in its annual energy and peak load growth over its 20-year planning horizon are due entirely to growth forecasted in the second half of the 20-year plan. As Staff

[38] Page 8-34 of PSE's 2017 IRP.
[39] Entitlement returns refers to the obligation of the United States to return a certain amount of power back to Canada as part of the Columbia River Treaty.
[40] Page 8-30 of PSE's 2017 IRP.

notes in its comments, historically, PSE's load forecasts have been overly optimistic. This was highlighted in a study by the Lawrence Berkeley National Laboratory of utility average annual growth rate of energy (AAGR).[41]

Figure 2: PSE's projected and actual average annual growth rate of electric energy

Period	PSE Projected AAGR	PSE Actual AAGR
2006-2014	1.75%	-0.19%
2012-2014	1.90%	-1.19%

The 2017 IRP projects flat to negative annual growth rates for the first 10 years of the Plan when there is projected aggressive energy conservation.[42] PSE models the first 10 years of conservation by applying 20 years of retrofit conservation measures from the conservation potential assessment (CPA) into the first 10 years of the IRP.[43] This and prior IRPs have shown the advantages of this compressed conservation schedule as it provides both a more cost-effective conservation portfolio and a reduction in PSE's revenue requirement. The acceleration of conservation is not unreasonable because the CPA relies on average regional conservation uptake rates that are normally exceeded by PSE's conservation performance. Furthermore, PSE has a history of aggressive conservation and the ability to achieve its targets has been demonstrated in every biennial conservation target to date.

However, the only conservation remaining in PSE's IRP model in years 11 through 20 are measures that are replaced on "burn-out" or new construction, with zero contributions from retrofit conservation measures. This lack of any retrofit conservation in the later years significantly affects the energy demand and therefore the projected need for new resources beyond year 10. PSE makes the same assumption for its natural gas demand forecasts and retrofit conservation. We agree with Staff's comments that PSE should assume in years 11 through 20 that a reasonable level of emerging retrofit conservation measures will become available in the market at cost-effective rates even though they cannot be accurately identified or predicted now.[44] This has been the experience in the region for more than three decades.

g. Greenhouse Gas Regulation and Carbon Price

Both State statute and Commission rule require an electric utility's expected case to represent the lowest reasonable cost, which includes "public policies regarding resource preference adopted by Washington state or the federal government, and the cost of risks associated with environmental effects including emissions of carbon dioxide."[45] That is, the Company must consider both known regulatory costs and the risk of future costs.

[41] Laurence Berkeley National Lab, "Load Forecasting in Electric Utility Integrated Resource Planning," October 2016, p. 25. https://emp.lbl.gov/publications/load-forecasting-electric-utility
[42] Page 5-8 of PSE's 2017 IRP.
[43] Appendix J of the IRP, Conservation Potential Assessment, pp. 16 and 45.
[44] Dockets UE-160918 and UG-160919 Staff Comments on PSE's 2017 Electric and Natural Gas IRP, pp. 9-10.
[45] WAC 480-100-238(2)(b).

Since the 2015 IRP, there have been significant changes to greenhouse gas emissions regulations, including increases to the renewable portfolio standards in California and Oregon, possible repeal and replacement of the Clean Power Plan (CPP), the implementation of Washington's Clean Air Rule (CAR), and now the rule's legal ambiguity. Despite the uncertainty surrounding the CPP and the CAR, there continues to be considerable legislative and regulatory risk associated with greenhouse gas emissions. In the last two years at the Washington State legislature, more than a dozen bills were introduced that would impose a cost on greenhouse gas emissions, or place limits on emissions.[46] Voters rejected a carbon tax at the ballot in 2016,[47] but another initiative has been filed, which may appear on the ballot in November 2018.[48] Additionally, Washington state and the federal government are in litigation by parties seeking regulation of the impacts of fossil fuels.[49] Local governments throughout PSE's service territory have established public policies to address climate change through aggressive greenhouse gas reduction goals.[50] Dozens of citizens testified concerning PSE's IRP at the Commission's public hearing arguing that their local public policies should be more fully recognized in PSE's next IRP.

Public policy is driving continued uncertainties in carbon policy, which exemplify the shifting regulatory terrain challenging the Company's planning efforts. In this environment, it is imperative that utility planners recognize the risks and uncertainties associated with greenhouse gas emissions and identify a reasonable, cost-effective approach to addressing them.

In its Base Scenario, PSE models the CAR regulations applying to both electric and gas utilities, the CPP across the Western Interconnection, and in-state resources transitioning from CAR to the CPP in 2022.[51] Both the CAR and CPP only applied to combined-cycle combustion turbines (CCCTs) and not to natural gas peaking plants. PSE concludes that the implied cost of carbon regulation is $27/metric ton. PSE runs seven Base Case Scenarios with different carbon regulations in its IRP, described as Scenarios 1, 9-14.[52]

The IRP is not clear on which set of carbon regulations is informing the Company's electric

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[46] *See,* e.g. HB 1144, HB 1155, HB 1646, HB 2230, HB 2839, SHB 2995, SB 5127, SB 5385, SB 5509, SB 5930, SB 6096, SB 6203, SB 6335, and SB 6629.

[47] Washington Carbon Emission Tax and Sales Tax Reduction, Initiative 732.

[48] Seattle Times, "New Washington initiative would put fee on carbon emissions", March 2, 2018. https://www.seattletimes.com/seattle-news/environment/new-washington-initiative-would-put-fee-on-carbon-emissions/.

[49] Associated Press, "Activists Sue Washington State for Tougher Climate Policy", February 16, 2018. https://www.usnews.com/news/best-states/washington/articles/2018-02-16/activists-sue-washington-state-for-tougher-climate-policym. , and Bloomberg, "Teenagers Defeat Trump's Move to Kill Climate Change Lawsuit", March 7, 2018. https://www.bloomberg.com/news/articles/2018-03-07/youths-defeat-trump-s-move-to-kill-climate-change-lawsuit.

[50] *See* Whatcom County, http://www.whatcomcounty.us/documentcenter/view/31641; Pierce County, http://www.co.pierce.wa.us/5558/Climate-Change-Resilience; King County, https://www.kingcounty.gov/services/environment/climate/strategies/strategic-climate-action-plan.aspx; and Thurston County, http://www.co.thurston.wa.us/planning/climate/climate_program.htm

[51] Page 4-3 of PSE's 2017 IRP.

[52] Page 4-3 of PSE's 2017 IRP.

resource action plan. Although for most of the Action Plan PSE appears to be using the carbon regulation in Base Case 1, which applies a carbon price to CCCTs and not peakers, it also states that it intends to acquire demand response using results from the comparison between Scenarios 9 and 14, which apply no carbon price and a carbon price to all thermal plants.[53] We are concerned with the lack of clarity in the Plan regarding how PSE used the Scenarios to decide its Integrated Resource Planning Solution.

RCW 19.280.030(f) requires utilities to prepare a long term plan that identifies the near term and future needs at the lowest reasonable cost and risk to the utility and its ratepayers. The term lowest reasonable cost means the utility must consider "the risks imposed on the utility and its ratepayers, public policies regarding resource preference adopted by Washington state or the federal government, and the cost of risks associated with environmental effects including emissions of carbon dioxide."[54]

By only modelling existing state regulation in its preferred portfolio, the Company's price of carbon does not consider the complete risk of additional regulation and, as such, risks not meeting statutory requirements. In future IRPs, PSE should incorporate the cost of risk of future greenhouse gas regulation in addition to known regulations when it develops its Integrated Resource Planning Solution. This cost estimate should come from a comprehensive, peer-reviewed estimate of the monetary cost of climate change damages, produced by a reputable organization. We suggest using the Interagency Working Group on Social Cost of Greenhouse Gases estimate with a three percent discount rate.[55] PSE should also continue to model other higher and lower cost estimates to understand how the resource portfolio changes based on these costs.[56]

h. Modelling Greenhouse Gas Abatement Costs

As a condition of extending the Company's IRP submittal due date, the Commission approved PSE's proposal to model the cost of available greenhouse gas abatement options.[57] Through the adoption of the Clean Air Rule, and numerous policy level proposals at the legislature, it is likely that utilities will be required to lower emissions from utility operation. A marginal abatement cost curve (MACC) is a tool that helps identify the lowest-cost options for reducing greenhouse gases.

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[53] Scenario 9 has no carbon price on any resource. Scenario 14 applies a carbon price to all resources.
[54] RCW 19.280.020(11).
[55] *See* Technical Support Document:-Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866- Interagency Working Group on Social Cost of Greenhouse Gases, United States Government. August, 2016. https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf.
[56] For example, for complying with Washington state Executive Order 14-04, the Washington State Energy Office recommends state agencies use the Interagency Working Group on Social Cost of Greenhouse Gases estimate with a 2.5 percent discount rate.
[57] Dockets UE-160918 & UG-160919, Order 01, ¶5.

We applaud PSE for being the first investor-owned utility in Washington to develop and publish a MACC in its IRP. It is important for policymakers to have this type of information available as they continue to consider policy options to lower greenhouse gas emissions. As Commission Staff states in its comments, there are ways for PSE to improve upon its MACC.[58] At this time, the MACC is best at ranking resource choices that best reduce emissions rather than as a source for the actual dollar impact. We expect that this type of information will be highly sought after by policymakers, and we urge PSE to continue working with Commission Staff, stakeholders, and academic experts to refine its MACC.

i. *Conservation*

In all 14 scenarios in PSE's IRP, the Company expects to purchase the same quantity of conservation regardless of the other inputs, such as low or high natural gas prices, or the application of a carbon tax.[59] PSE's analysis in Chapter 6 also shows that a lower discount rate for residential conservation does not have a material impact on the amount of conservation purchased. Both of these outcomes seem implausible.

In its comments, Staff recommends that PSE create smaller electric conservation bundles particularly around anticipated cost-effectiveness price points for smaller groups of individual measures. Alternatively, Staff recommends that PSE model individual measures separately to determine more accurately the amount of cost-effective conservation available. Finally, Staff recommends that PSE examine the effect of a lower discount rate for residential conservation in the 2019 IRP.[60]

The Company should work with Staff, its Conservation Resources Advisory Group, and the Council to refine its conservation bundling. The Company should also use a lower discount rate for residential conservation in the Base Case as it is a more accurate representation of the opportunity cost of capital and the risk of the investment for the customers who are choosing to purchase energy efficiency.

j. Gas Peak Day Load Forecast

PSE design peak day used in this plan is a 52 heating degree-day, which equates to 13 degrees Fahrenheit average temperature for the day.[61] PSE adopted this standard in its 2005 Least Cost

[58] Dockets UE-160918 and UG-160919 Staff Comments on PSE's 2017 Electric and Natural Gas IRP, pp. 13-14.
[59] Page 2-7, figure 2-4 of PSE's 2017 IRP.
[60] Docket UG-121207, Policy Statement on the Evaluation of the Cost-Effectiveness of Natural Gas Conservation Programs, "For residential participants, the upfront costs are often small enough so as not to require long-term financing. Accordingly, residential programs evaluated under the TRC should use a discount rate reflective of minimal financing needs and low risk. We determine that the interest rate of U.S. Treasury notes is a reasonable indicator of low-risk investments."
[61] IRP Appendix E, E-12.

Plan, which was the forerunner to the IRP. Staff recommends that PSE consider revisiting its peak gas day standard in the next IRP to see if it needs to be updated.[62]

k. Tacoma LNG facility

PSE's second natural gas Action Plan Item is to complete the Tacoma LNG facility. PSE assumes that the Tacoma LNG facility will be completed and in operation prior to the 2019 winter season and may be needed to provide gas to meet core customer peak needs as soon as the 2021 winter season. However, even at this later stage in the project's development, the project has ongoing and potentially significant permitting issues.[63] Given that the plant is not completed or fully permitted, we agree with Staff that the Company's assumption that a not-yet-operational resource will be available comes with some significant risk to the Company's gas supply for core customers. PSE's next IRP must address what the Company will do in the event the LNG plant or pipeline upgrades are significantly delayed or cancelled.

l. Stakeholder process

As this commission has noticed, PSE's IRP meetings and presentations have increasingly attracted scrutiny from the public, environmental advocacy groups, and vendors. This has put additional stakeholder engagement pressure on PSE's IRP team. While we are aware of stakeholder complaints around the discussions of major transmission and distribution planning, we believe the Company adeptly managed its stakeholder process overall. In addition to hiring a facilitator to moderate advisory group meetings, midway through this IRP process PSE hired an internal process manager to facilitate the interaction between the Company and the stakeholders. We heard from our Staff and the stakeholders that the additional hire greatly improved the process. We applaud PSE for recognizing an issue and moving to remediate it mid-cycle.

IV. Conclusion

The Commission acknowledges that Puget Sound Energy's 2017 Electric and Natural Gas Integrated Resource Plan complies with RCW 19.280.030, WAC 480-100-238, and WAC 480-90-238. The Commission expects PSE to follow the recommendations outlined in this letter as it develops future IRPs.

V. Separate Statement of Commissioner Balasbas on Part III g.

I agree with my colleagues that in future IRPs, PSE should incorporate the cost of risk of future greenhouse gas regulation in addition to known regulations in its Integrated Resource Planning Solution (i.e. lowest reasonable cost portfolio). However, for the reasons outlined below, I

[62] Dockets UE-160918 and UG-160919 Staff Comments on PSE's 2017 Electric and Natural Gas IRP, p. 18.
[63] Puget Sound Clean Air Agency, "Current Projects: Puget Sound Energy - LNG Facility Tacoma." http://www.pscleanair.org/460/Current-Permitting-Projects.

respectfully disagree with my colleague's expectation that PSE use in its lowest reasonable cost portfolio the social cost of carbon as the proxy for future greenhouse gas regulation.

The 2018 legislature considered, but did not take final action on, House Bill No. 2839 and Senate Bill No. 6424. These bills, among other provisions, amended Commission statutes to require use of a "greenhouse gas planning adder" when evaluating integrated resource plans as well as intermediate-term and long-term resource options selected by electrical and gas companies under Commission jurisdiction.[64] The greenhouse gas planning adder can also be referred to as the social cost of carbon. The legislature's mere consideration of this provision indicates there is not clear authorization in current statute for the Commission to require use of the social cost of carbon in IRPs.

The expectation for PSE to use the social cost of carbon in its preferred portfolio is a clear statement that the 2018 legislation was irrelevant. I strongly disagree and would instead defer to the legislature's judgment of the Commission's statutory authority.

When commenting on IRPs, it is appropriate for the Commission to request scenarios using specific assumptions. However, I do not believe the Commission should mandate use of specific assumptions in the ***utility's*** preferred portfolio. My preference would have been to ask PSE to model a separate scenario in its 2019 IRP that uses the social cost of carbon. Then PSE can decide whether that model outcome should be used in its lowest reasonable cost portfolio.

Finally, I disagree with my colleagues mandating the use of the social cost of carbon to represent the "lowest reasonable cost" portfolio. As the Federal Energy Regulatory Commission recently stated in an order, "Without complete information, an analysis using the Social Cost of Carbon calculations would necessarily be based on multiple assumptions, producing misleading results."[65] While IRPs are by necessity assumption driven, I am concerned that requiring use of a speculative tool to choose a preferred portfolio could lead to higher than necessary rates for utility customers.

[64] ESHB 2839, Section 3
[65] FERC Docket Nos. CP14-554-002, CP15-16-003, CP15-17-002 Order on Remand Reinstating Certificate and Abandonment Authorization, ¶ 41 (Issued March 14, 2018)